E21177-TE

AURORA ENERGY RESEARCH

DRAFT

Study ‘CO_2-free flexibility resources’

Final Draft – October 2021

Agenda

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Based on MEA's requirements, we propose an approach in four phases that feed into a final report

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MEA's requirements

- The Ministry of Economic Affairs and Climate Policy (MEA) wants to investigate **options for carbon-free flexible power supply in an increasingly decarbonising power market**
- MEA is seeking to understand
  - **Which sources** of carbon-free flexibility are available
  - How their **economic and technical characteristics** compare
  - Which **contributions they can make in the Dutch power market** medium or longer term
- MEA would like to investigate **which policy environment** is needed to ensure the **timely provision** of sufficient carbon-free electricity sources

Approach

The scope of the project is divided into four packages:

A Identification of the **potential and characteristics** of CO_2-free flexible capacity
- Development of dashboard with key metrics

B Evaluation of the **business cases** of the various flexibility options in 2030
- Alignment on base case
- Analysis of required income for technologies on a 1 MW basis, revenues achieved in project base case and gap to profitability
- Sensitivities for different commodity prices and flex in neighboring countries

C Quantification of the **need for flexibility and determination of the most cost-efficient path** to CO_2-free security of supply
- Calculation of loss of load and need for flexibility in different weather years
- Proposal for technology mixes to close the capacity gap

D Recommendations to **bridge the gap to profitability** for promising technologies
- Overview of obstacles
- Proposal for solutions

Sources: Aurora Energy Research

Executive Summary

1 / 3

- In Package A, we provide a general overview of the most relevant technologies that are able to offer flexibility to the electricity system, split into the categories of Dispatchable Production Technologies, Storage Technologies, Demand Flexibility Technologies and Other Technologies.
  - As Demand Flexibility Technologies are not financed through the wholesale market, but rather the investments are made for other purposes (e.g. heating), these assets are assessed differently then the others. Their business case is not quantified in package B, but rather they are an integral part of our Base Scenario and will be essential to reduce the need for flexibility in the system.
- In Package B, the business case of the different technologies is assessed for the Dutch power market in 2030. Our Base Scenario for 2030 is aligned with EZK and Tennet[1]. The analysis shows that almost none of the assessed technologies (excluding Demand Flex.) have a positive business case. There is no loss of load occurring in this scenario in 2030, as the remaining gas capacity offers enough flexibility to provide power at moments of low solar and wind production.
  - The best performing flexibility assets in the 2030 power system are those with low investment costs, like e-methane, biogas and hydrogen CCGTs. Additional interconnection with Germany could also be beneficial, but seems more driven by the need for flexibility in the German market, as in our scenario we assume an early phase-out of coal plants to reach Net Zero.
  - From a more abstract cost perspective (i.e. LCOE), none of the Dispatchable Production Technologies have lower costs than a natural gas CCGT, given our commodity price scenario for 2030[2]. When running a limited amount of hours per year (i.e. 1500 h/year) retrofitted biomass, biogas and hydrogen power plants have the lowest integral cost. For higher usage (i.e. 4500 h/year) gas and biomass plants with CCS perform slightly better. Of the Storage Technologies, lithium-ion batteries together with the more experimental vehicle-to-grid have the lowest cost, and are even cheaper than CCGTs when used for 1500 h/year.
    - Insights from the profitability and cost perspective differ, as when assessing profitability the actual running hours of an asset in our 2030 power system are used, instead of a fixed amount of hours. Therefore, the profitability perspective is better suited for assessing the likeliness of new assets entering the market.

1) Numbers from the KEV2020 of PBL, the II3050 study of Gasunie and Tennet and Aurora's own view of the market have been used to construct our Base Scenario. 2) In our Net Zero scenario, we assume gas prices have dropped from their high levels in Oct-21 to 21 €/MWh in 2030.

Source: Aurora Energy Research

Executive Summary

2 / 3

- In Package C, focussing on the period post 2030, we find Demand Flexibility Technologies greatly reduce the need for additional capacity in the system. However, without additional CO2-free production and storage flex capacity the Dutch gas fleet cannot be phased out to reach climate targets, as loss of load would occur at unacceptable levels[1].
  - Demand Flexibility Technologies do not only help to reduce the need for other flexible capacity, but also help the business case of renewables, by concentrating demand at moments of high renewable production. The extra flexible demand prevents capture prices of wind and solar from dropping to zero, even though renewable capacity more than doubles between 2030 and 2050, which makes merchant renewable projects more feasible.
  - For CO2-free flex production and storage capacity to be profitable in a decarbonising power system, extreme price peaks and (potentially) loss of load in some hours of the year needs to be accepted. In light of the public backlash on recent and historic price surges, the political support for such a system might be limited. The Optimal Profitability scenarios do have the lowest overall system costs. In contrast, to guarantee Full Security of Supply, flex capacity in our scenarios require additional payments on top of wholesale market revenues. Alternatively, there might be role for rarely used industrial demand response from new electrification.
  - Retrofitted BECCs and H2 CCGTs are best positioned to provide long-duration flex towards 2050, as they can be profitable even in a Full Security of Supply scenario from 2035 and 2042 repetitively. For nuclear, 3+ gen. plants are not profitable in either of the scenarios and nuclear SMR is barely profitable in opt. profitability. Gas CCS can only be profitable before 2045 in the scenarios when retrofitted.
  - Back-up and short-duration flex capacity is never profitable in scenarios with Full Security of Supply. In the Optimal Profitability scenario, back-up capacity can be profitable by producing in a few hours per year with extreme prices. Li-ion batteries at the estimated cost levels for 2030 are still not profitable when only considering the wholesale market, but if the cost reduction towards 2050 materializes, they will become profitable if enough scarcity prevails. Also, they could benefit from additional revenue streams like the imbalance market to enhance their business case.

1) In 2050 if no extra capacity enters the system there could be around 1000 h/year of loss of load and even up to 2000 hours/year in the most extreme weather year, with a peak loss of load of up to 23 GW.

Source: Aurora Energy Research

Executive Summary

3 / 3

- In Package D, we provide an overview of key non-financial[1] hurdles to market entry and scale-up for a selection of the most promising flexible CO_2-free technologies. We also suggest potential solutions to these hurdles and provide an estimate of the lead-in time for the first 1 GW of each technology.
  - Lithium-ion batteries see the fewest non-financial hurdles, with the main one being possible scarcity issues surrounding some of the metals used in their construction.
  - For flexible-demand technologies – smart EVs, flexible household heat pumps, electrolysers, and industrial power-to-heat – most key hurdles stem from lacking incentives in price, taxes, and tariffs. Non-variable energy prices and fees give households little incentive to flexibilise their demand, and electrification is rendered costly for industrial consumers by high grid fees.
  - Fuel-combusting technologies – biogas, biomass, hydrogen, and e-methane – often suffer from issues pertaining to their fuel source. Biofuels are politically and publicly unpopular, due mainly to resource competition with agriculture and concerns on deforestation. CO_2-free hydrogen and e-methane are as of yet only commercially available in small quantities; production could likely be scaled up quickly, but insufficient renewable electricity and infrastructure may pose a problem.
  - Nuclear fission plants suffer strongly from their long construction times – risking a technological lock-in and too late deployment for climate targets – as well as NIMBYism and waste-storage concerns.
  - Furthermore, to achieve decarbonisation reinforcement of the electricity grid is important for all technologies. Increased RES generation and electrification in particular – depends on the capacity of the electricity grid to handle them. Although flexibilisation of electricity demand can help reduce congestion, the success of the electrification that enables much of such flexibilization – e.g. electric industrial boilers – depends nonetheless on increased grid capacity.

1) i.e. other than lack of profitability, which is analysed in Package B and C

Source: Aurora Energy Research

We model the whole of Europe in an integrated manner

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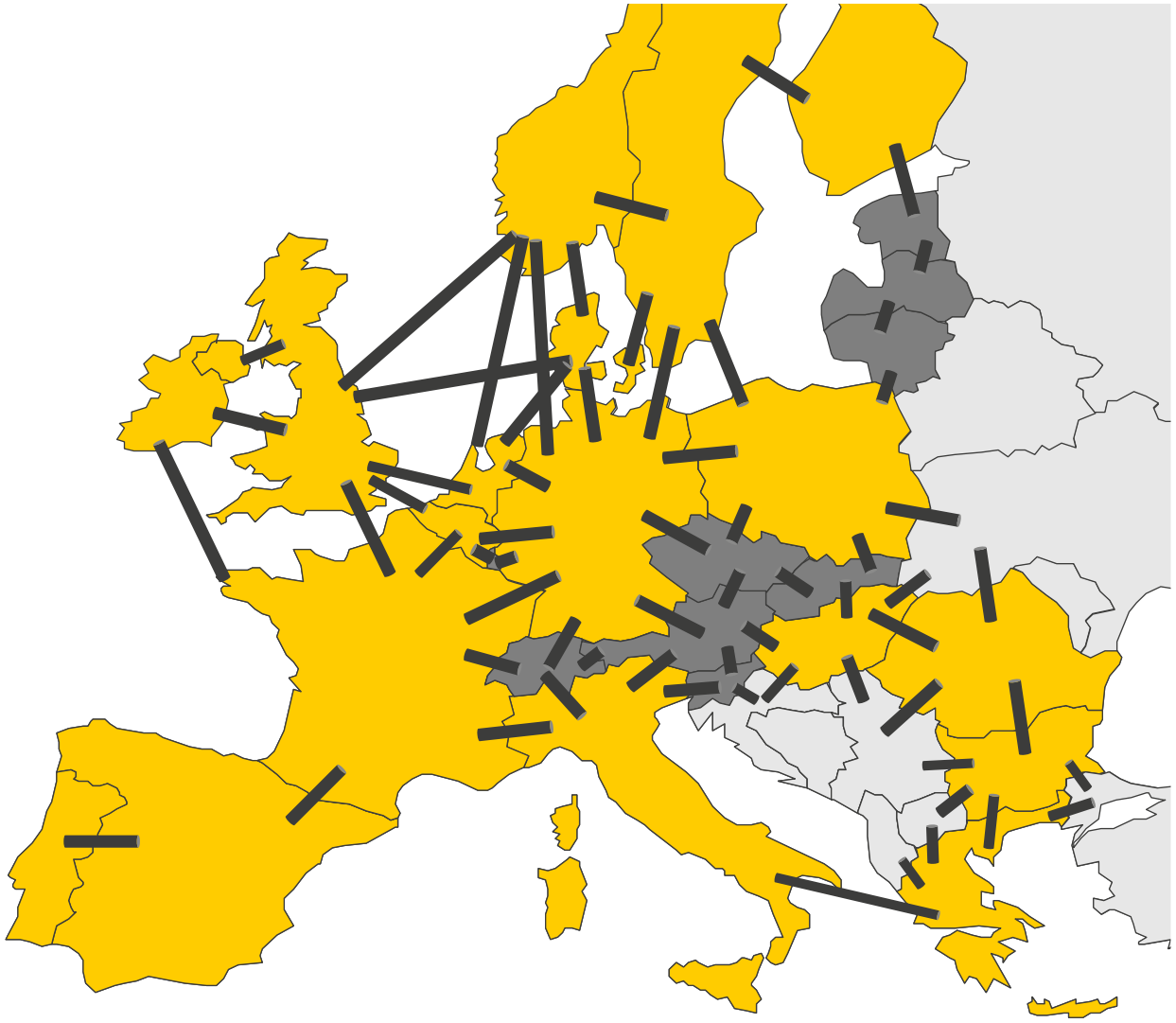
Endogenous interconnector flows based on price differentials

Interdependence of prices and capacities in different regions

High granularity right down to individual plant level



Key

- Individual plant
- Plant aggregation
- Higher aggregation
- Interconnector[1]

Modelling granularity

1) Sizes and lengths of interconnectors are for visual representation only, illustrative and are not to scale

Source: Aurora Energy Research

Unique, proprietary, in-house modelling capabilities underpin Aurora's superior analysis

AURORA

3 Integrated Models

Gas (AER-GAS) ↔ **Power markets (AER-ES)** ↔ **Global Commodities (AER-GLO)**

INPUTS

- Technology
- Policy
- Demand
- Commodity prices[1)]
- Weather patterns

Dispatch model

- Hourly
- Iterative modelling
- Dynamic dispatch of plant
- Endogenous interconnector flows

Continuous iteration until an equilibrium is reached

Investment decisions module

- Capacity market modelling
- Capacity build / exit / mothballing
- IRR / NPV driven
- Detailed technology assessments

OUTPUTS

- Capacity mix
- Generation mix
- Wholesale & imbalance prices
- Capacity market prices
- Profit / Loss and NPV
- Electric vehicle charging

Up to 70	c. 85k	~10k	30+
specifications modelled for each plant	investment hours on modelling capabilities	model runs per week	strength of modelling team globally

1) Gas, coal, oil and carbon prices fundamentally modelled in-house with fully integrated commodities and gas market model

Source: Aurora Energy Research

Advantages of Aurora approach

- Flexible and nimble because we own the code
- Transparent results
- State-of-the-art infrastructure
- Zero dependence on black-box third-party software (e.g. Plexos)
- Constantly up to date through subscription research
- Ability to model complex policy changes very quickly

Agenda

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Based on economics and the role of different technologies in the power market, we distinguish four categories of technologies

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A Dispatchable Prod. Technologies

- Technologies that can freely dispatch to the market and can be characterized by their **levelized costs of electricity** (LCOE)
- Assets are **financed** through the **wholesale market** – they will dispatch against **their marginal costs** and depend on the **absolute height of power prices** to recover their costs

B Storage Technologies

- Technologies that buy power from the market in low price hours and then later sell it again at higher prices – characterized by their **levelized cost of storage** (LCOS)
- Assets are **financed** through the **wholesale market** – they depend on the **spread between high and low-price hours** (not on the absolute level) in order to recover their costs

C Demand flexibility Technologies

- Technologies do not supply electricity but can **adjust their demand subject to certain constraints,** e.g. storage size, degradation, consumption patterns
- Assets are **not financed through the wholesale market** – investments mostly made for other purposes (e.g. heating) but assets can contribute flexibility and hence to security of supply

D Other Technologies

- **Renewable assets** also are characterized by their **levelized costs of electricity** (LCOE) and financed through the **wholesale market**, but **cannot freely dispatch power**
- **Interconnectors** are built based on **socio-economic cost-benefit** analysis – their economics depend on **prices differences** between markets

Technologies

- *Biomass*
- *BECCS*
- *Biogas*
- *Gas CCS*
- *Hydrogen*
- *E-methane*
- *Metal fuels*
- *Nuclear energy*

- *Batteries – Li-Ion*
- *Batteries – Redox-Flow*
- *Compressed Air*
- *Vehicle to grid*

- *Heat Pumps*
- *Hybrid Heat Pumps*
- *Electric Boilers*
- *EV Smart Charging*
- *Industrial DSR*

- *Additional RES Capacity*
- *Interconnection*

Source: Aurora Energy Research

Based on economics and the role of different technologies in the power market, we distinguish four categories of technologies

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Technologies

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- *Hydrogen*
- *E-methane*
- *Metal fuels*
- *Nuclear energy*

B Storage Technologies

C Demand flexibility Technologies

- *EV smart charging*
- *Industrial DSR*

D Other Technologies

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- *Additional RES Capacity*
- *Interconnection*

Remarks for the following section:

- We show detailed plant characteristics and will include the technologies with 1 MW into the model to test their profitability
- As part of the project, we will determine the capacity of each technology that we assume to be in the power market
  - We present information on expected build-out and / or pilots in order to calibrate at which point in time and how these technologies contribute to the security of supply
- A plant will dispatch to the market when the power price exceeds its marginal cost
- Our power market model takes into account ramping behavior of plants (e.g. ramping cost) and thus also reflect the cost of these plants operating flexibly
- The technologies in this section are well suited to replace assets in the current power system that provide baseload power, given they are not constrained by their duration

Source: Aurora Energy Research

Sustainable wood pellets are a proven technology to provide carbon-free power – policy debate on biomass ongoing, supply limited

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Description

- Biomass can be used for electricity production, heat production, or both (in a CHP)
- Due to the short carbon cycle, the burning of biomass for electricity and heat production is considered CO_2-free
- An effective use of biomass is the burning of wood pellets in large plants (e.g. former coal plants), as they have high efficiencies and require low capital investment

Price for wood pellets

Key parameters for 2030

Currencies in real 2020

Burning of wood pellets in coal plants

Parameter	Retrofit Coal	Newbuild	Unit
Lifetime	30	40	Years
Typical unit size	700-1,100	Similar	MW
Cost – CAPEX	450,000	2,000,000	EUR/MW
Cost – Fixed O&M	30,000	Similar	EUR/MW/a
Cost – Variable O&M	3	Similar	EUR/MWh
Cost – Fuel[2]	~28-35	Similar	EUR/MWh
Efficiency (HHV)	~35-40	~40-45	%

Potential barriers for adoption

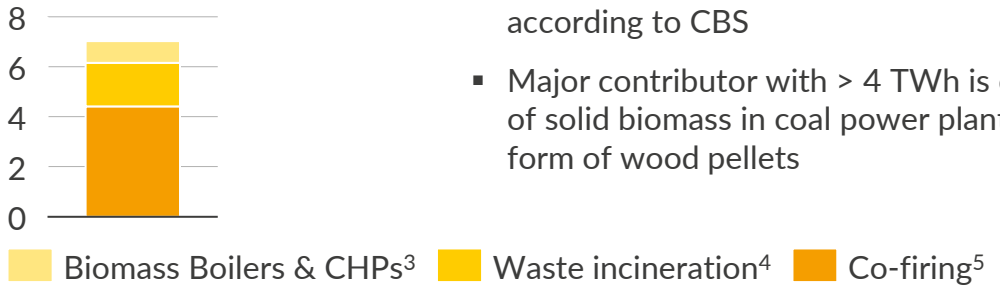
- The use of biomass in the Netherlands is becoming increasingly controversial
  - The predominant concern is that the import of biomass will do irreversible damage to nature abroad, e.g. in Latvia and Estonia
  - These concerns persist despite the obligation to burn only sustainably harvested biomass where subsidies are received[1] – certification of sustainability might need to be improved
- Consensus in parliament regarding wood-based biomass for energy has shifted such that parliamentary majority is currently opposing – but policy debate is ongoing
- On an EU level, biomass demand will likely exceed supply – at least without putting additional pressure on the environment

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: High

Electricity Output NLD 2020

TWh



- Biomass as proven technology that can provide carbon-free power – ~7 TWh of electricity output from non-gaseous biomass in the Netherlands in 2020 according to CBS
- Major contributor with > 4 TWh is co-firing of solid biomass in coal power plants in form of wood pellets

1) The use of sustainable wood pellets in a biomass installation of up to 100 MW el. and at least 5 MWh was subsidized in the SDE++ autumn 2020 round; 2) Fuel price before plant efficiency – price for 1 MWh fuel; 3) Combustion of solid or liquid biomass for decentralized electricity production, with or without simultaneous heat production; 4) Waste from plants and animals that is combusted as part of municipal waste; 5) Wood pellets in coal power plants

Sources: Aurora Energy Research; Ipsos; Pricewise; CE Delft; CBS; Tweede Kamer; Material Economics

BECCS could become a large-scale negative emissions technology – similar constraints as for biomass and high costs prevail

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Description

- BECCS is a combination of the use of bioenergy and carbon capture and storage (CCS) – it could remove CO_2 from the atmosphere and serve as carbon sink
- For instance, CCS could be added to large former coal plants that have been converted to the burning of biomass
- BECCS is seen as an element in the energy transition that could compensate for overshooting emission targets in other hard-to-abate sectors

We will add the cost of carbon as a negative item in the VOM, reflecting BECCS being a negative emissions technology

Based on efficiency for biomass plants, includes 7% efficiency penalty for CCS

Key parameters for 2030

Currencies in real 2020

Parameter	Retrofit Coal	Newbuild	Unit
Lifetime	30	40	Years
Typical unit size	700-1,100	Similar	MW
Cost – CAPEX	1,000,000	3,000,000	EUR/MW
Cost – Fixed O&M	80,000	Similar	EUR/MW/a
Cost – Variable O&M	3	Similar	EUR/MWh
Cost – Transport & storage	11	Similar	EUR/MWh
Cost – Fuel[1]	~28-35	Similar	EUR/MWh
Efficiency (HHV)	~28-33	~33-38	%

Potential barriers for adoption

- The net carbon balance of BECCS is yet to be determined
  - The carbon capture efficiency of CCS is only at 80-95%
  - The direct and indirect emissions of the biomass production, including process, transport, and effects on the ecosystem
- BECCS relies on sufficient availability of sustainable biomass – *see respective slide*
- Infrastructure for storage and transport of CO_2 is required for the successful implementation of BECCS – policies and governance around CCS in early stage

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: Low - Medium

- A BECCS pilot project has been launched at the Drax Power Station, in the UK
  - Drax has invested £400,000 in the pilot, and claims that BECCS could capture 8 million t CO2/year by 2030 – high level of subsidies required according to think tank Ember for power station to operate
- The first large scale BECCS project is in Illinois
  - It produces ethanol from corn, while the CCS facility captures 1 million t CO2/year and stores it in a dedicated geological storage site under the facility

1) Fuel price before plant efficiency – price for 1 MWh fuel

Sources: Aurora Energy Research; RVO; PBL; Global CCS Institute; Chalmers University Gothenburg, EMBER

Biogas could be used to replace methane in existing gas assets – availability eventually limited, fuel costs higher than natural gas

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When adding higher-cost fuels to gas assets, CCGTs have a cost advantage over OCGTs, as the lower efficiencies of OCGTs lead to worse economics already for very low running hours[2]

Description

- Natural biogas is produced through fermentation of biomass
- Biogas could be used to replace methane in current gas plants
- Two more experimental gasification processes (thermal & supercritical gasification) are currently being tested

Key parameters for 2030

Currencies in real 2020

Parameter	Retrofit CCGT	Newbuild	Unit
Lifetime	20	30	Years
Typical unit size	500–1,500	Similar	MW
Cost – CAPEX	26,000	650,000	EUR/MW
Cost – Fixed O&M	19,000	Similar	EUR/MW/a
Cost – Variable O&M	2	Similar	EUR/MWh
Cost – Fuel[3,4]	~66	Similar	EUR/MWh
Efficiency (HHV)	~50-55	~55-60	%

Potential barriers for adoption

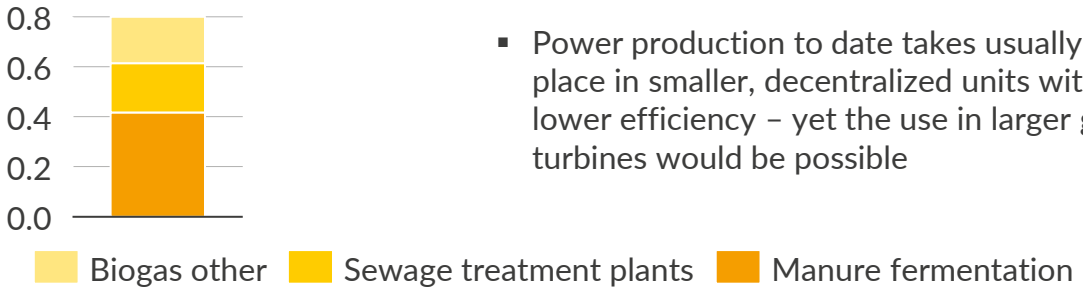
- Sources of natural biogas are limited
  - Potential estimated at ~8 TWh in 2020 and ~22 TWh in 2030 for fermentation for the Netherlands by RVO
  - Agricultural collectives are starting to initiate joint biogas production from manure[1] but as the government plans to move to circular agriculture and thus smaller size of livestock, the future availability of manure could affect the biogas supply
- The use of biogas for power production is also subject to debate, as biogas could be used for processes which are harder to decarbonize

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: High

Electricity Output NLD 2020

TWh



- Biogas also is a commercially mature technology, but with a small contribution - ~0.8 TWh of electricity output in 2020 in the Netherlands
- Power production to date takes usually place in smaller, decentralized units with lower efficiency – yet the use in larger gas turbines would be possible

1) RVO, *Vergisting and vergassing*, as of July 2021; 2) OCGTs can be relevant, however, as plants that do run in some years but not in others. We assume ~450,000 EUR/MW CAPEX, ~10,000 EUR/MW/a Fixed O&M, 2 EUR/MWh Variable O&M and ~35-40% efficiency for new OCGTs; 3) Fuel price before plant efficiency – price for 1 MWh fuel; 4) SDE++ Basisbedrag 2021;

Sources: Aurora Energy Research; RVO

CCS can be added to gas assets to strongly reduce carbon footprint – infrastructure for transport / storage and storage space required

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Description

- In a conventional gas asset (retro-) fitted with carbon capture and storage (CCS), the emitted CO_2 is captured post-combustion, compressed and thereafter stored
- Post-combustion CCS is thus seen as a technology that allows the use of existing gas assets, while making them CO_2 neutral[1]

Based on efficiency for gas turbines, includes 7% efficiency penalty for CCS

Key parameters for 2030

Currencies in real 2020

Parameter	Retrofit CCGT	Newbuild	Unit
Lifetime	20	30	Years
Typical unit size	500-1,500	Similar	MW
Cost – CAPEX	1,000,000	1,500,000	EUR/MW
Cost – Fixed O&M	38,000	Similar	EUR/MW/a
Cost – Variable O&M	2	Similar	EUR/MWh
Cost – Transport & storage	11	Similar	EUR/MWh
Cost – Fuel[2,3]	21	Similar	EUR/MWh
Efficiency (HHV)	~43-48	~48-53	%

Potential barriers for adoption

- The carbon capture efficiency of CCS is 80-95%, so even the best-in-class assets are not fully carbon-neutral
- Support and/or space for CO_2 storage may eventually prove limited – technologies beyond geological storage (e.g. ocean storage) are still in early phases
- Infrastructure for storage and transport of CO_2 is required for the successful implementation of CCS – policies and governance around CCS in early stage

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: Medium

- In Europe ten large-scale CCS facilities are being developed and are intended to be operational in the 2020s
- In Ireland, a post combustion CCS project is being developed by ERVIA, the CCS-equipped CCGTs and refinery shall start operation in 2028
  - The project is expected to capture 2 Mt CO_2 per year, then transport and store in the Celtic Sea
- In the UK, for the two ~900 MW CCGTs Peterhead and Keadby 3, Equinor and SSE Thermal plan to retrofit them with CCS and install infrastructure to transport and store CO_2

1) Subsidies for CCS under the current SDE++ framework do not apply to electricity production; 2) Fuel price before plant efficiency – price for 1 MWh fuel; 3) Natural Gas

Sources: Aurora Energy Research; IPCC; Eurometal

Hydrogen-burning assets can provide seasonal storage – high fuel cost by 2030, infrastructure for transport required

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Description

- While hydrogen has applications of its own in industry, transport and heating, it can also be used to produce power
- Purpose-built CCGTs[1] or OCGTs[2] could be used, or existing gas-firing assets could be converted
- Hydrogen can be used for seasonal storage, making it a potentially powerful contributor to system flexibility
- Subsidies for both blue and green hydrogen are in place in the SDE++ framework

Depending on type of low carbon H2: In 2030, green H2 expected to be most expensive, followed by imported H2 and blue H2 – but cost of blue H2 rather constant, while the other two will decline over time

Potential barriers for adoption

- Hydrogen is expected to be still an expensive fuel by 2030, leading to high variable costs
- Domestic production of green hydrogen in the Netherlands might not be cost-competitive 2030, while imports (e.g. from North Africa) might be politically contentious
- There is a need to develop an infrastructure system: large-scale application of hydrogen-powered plants would require dedicated pipelines and a storage system

Key parameters for 2030

Currencies in real 2020

Parameter	Retrofit CCGT	Newbuild	Unit
Lifetime	20	30	Years
Typical unit size	500–1,500	Similar	MW
Cost – CAPEX[3]	200,000	650,000	EUR/MW
Cost – Fixed O&M	19,000	Similar	EUR/MW/a
Cost – Variable O&M	2	Similar	EUR/MWh
Cost – Fuel[4]	~65-110	Similar	EUR/MWh
Efficiency (HHV)	~50-55	~55-60	%

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: Medium - Low

- Engie has announced plans to modernize its Maxima plant (a CCGT) in Lelystad to enable the co-firing of hydrogen
  - The efficiency will be increased to over 60% and 35 MW will be added to the 440 MW-unit - the overhaul should be completed by 2023
- The Magnum plant in Eemshaven has already been adapted to burn hydrogen and a battolyser will be installed for combined hydrogen production and electricity storage

1) Combined cycle gas turbine; 2) Open cycle gas turbine; 3) Our cost estimates assume the presence of a large scale H2 infrastructure (transport & storage); 4) Fuel price before plant efficiency – price for 1 MWh fuel

Sources: Aurora Energy Research; Energeia

E-methane could be burned in existing gas assets without additional investment – efficiency losses in process drive high fuel costs

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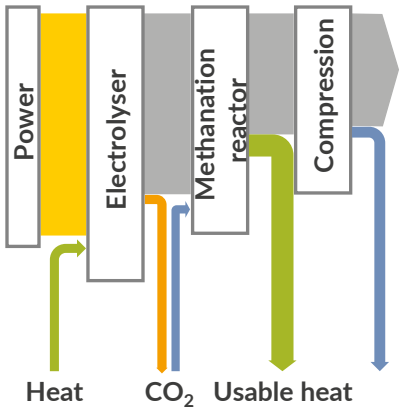
Description

- E-methane, or 'green methane' has the same chemical structure as natural gas: CH_4
- Green methane can be produced from hydrogen and carbon dioxide, making its use CO_2-neutral
- A gas-burning CCGT[1] or OCGT[2] could run entirely or partly on e-methane
- Existing gas infrastructure (e.g. distribution grid) does not need to be repurposed for the use of e-methane



Key parameters for 2030

Currencies in real 2020

Parameter	Retrofit CCGT	Newbuild	Unit
Lifetime	20	30	Years
Typical unit size	500–1,500	Similar	MW
Cost – CAPEX	26,000	650,000	EUR/MW
Cost – Fixed O&M	19,000	Similar	EUR/MW/a
Cost – Variable O&M	2	Similar	EUR/MWh
Cost – Fuel[3,4]	~158[5]	Similar	EUR/MWh
Efficiency (HHV)	~50-55	~55-60	%

Potential barriers for adoption

- E-methane is produced using hydrogen and CO_2 – supply / storage infrastructures for both inputs need to be created and maintained (e.g. co-location with BECCS)
- Efficiency losses in the production of e-methane are a key concern – costs for e-methane are ~50% higher than for H2, ~20% of H2 is lost in the process
  - While the gas turbine burning methane eventually is highly efficient, final 'power-to-power' efficiency is only around 30%

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: Medium - Low

- In principle, all gas-fired units in the Netherlands could be run on e-methane, which means a potential fleet of over 10 GW is already in place
- There are no ongoing pilots, although Engie mentioned co-firing hydrogen and e-methane in its Maxima plant as a possibility

Electric power | Chemical power | Losses | Thermal power

1) Combined cycle gas turbine; 2) Open cycle gas turbine; 3) Fuel price before plant efficiency – price for 1 MWh fuel; 4) Based on 80% efficiency of H2 to CH_4 conversion as well as other costs for methanation, e.g. for carbon; 5) only based on green H2

Source: Aurora Energy Research

Metal fuels are being developed as a possible alternative to hydrogen for seasonal storage –technological / commercial maturity still low

AURORA

Description

- Metal powder is a carbon-free fuel that could be used in existing coal assets
- After combustion, iron oxide (rust powder) remains
- Using hydrogen, the iron oxide can be reduced back to iron, releasing only water
- As such, iron powder can serve as seasonal storage of renewable energy

Key parameters for 2030[1]

Currencies in real 2020

Parameter	Retrofit Coal	Newbuild	Unit
Lifetime	30	40	Years
Typical unit size	700-1,100	Similar	MW
Cost – CAPEX	316,000	2,000,000	EUR/MW
Cost – Fixed O&M	30,000	Similar	EUR/MW/a
Cost – Variable O&M	3	Similar	EUR/MWh
Cost – Fuel[2,3]	~110-173	Similar	EUR/MWh
Efficiency (HHV)	~35-40	~40-45	%

Potential barriers for adoption

- The lower energy density and higher variable costs that go with the combination of iron with hydrogen form a potential roadblock to commercial viability
- Combustion systems that can efficiently burn the metal fuels have to be developed on a larger scale – the technology readiness level of the technology is still low

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: Low

- Eindhoven University of Technology aims to scale up the development of iron powder as an alternative fuel for power plants
  - Burning of iron powder has been applied at a brewery in Lieshout using a 100 kW installation
  - Goal is to scale to 1 MW next, 10 MW by 2024 and be able to convert a full fired power station by 2030 (through follow-up project SOLID); scale-up supported by EU funds

1) Asset-specific parameters based on a typical coal-burning asset; efficiency and variable costs specific to the iron oxidation-reduction cycle; 2) Fuel price before plant efficiency – price for 1 MWh fuel; 3) Based on 72% efficiency of H2 (re-) conversion as well as other fixed process costs

Sources: Aurora Energy Research; Energeia; Eindhoven University of Technology

High investment cost and lifetime of require long-term commitment to nuclear – SMRs yet to prove commercial viability

AURORA

Description

- Nuclear power is the use of nuclear reactions to produce electricity, mostly through nuclear fission
- While typically nuclear reactors have been built in larger unit sizes (>500 MW), small modular reactors (SMR) could lead to a breakthrough
  - They are expected to have capacities of up to 300 MW
  - Their construction is assumed to be more standardized which shall help to reduce investment cost

Key parameters for 2030

Currencies in real 2020

No commercial maturity at this point

Parameter	Large unit (Gen. III+)[2]	Small Modular Unit (Gen. III+)	Unit
Lifetime	60	Similar	Years
Typical unit size	~1,600-1,800	<300	MW
Cost – CAPEX	5,200,000	4,500,000	EUR/MW
Cost – Fixed O&M	80,000	Similar	EUR/MW/a
Cost – Variable O&M	14	Similar	EUR/MWh
Cost – Fuel[3]	4	Similar	EUR/MWh
Efficiency (HHV)	40	45	%

Potential barriers for adoption

- Capital expenses are high and lead times for constructing nuclear power plants are long (10-15 years), which implies high project risks – cost escalation after start of construction has often been observed in the past
- Because of high CAPEX and lifetime, long term commitment are among the main conditions for realizing a new nuclear power plant
- Location-wise, only Borssele in the province of Zeeland persists as a relevant candidate for new plants in the Netherlands – two new reactors proposed close to current site by EPZ in 2020
- Long-term treatment of radioactive waste remains a concern both from an environmental and an economic perspective
- As they ramp slowly, nuclear plants are not well suited to flexible production

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: High for large units, unproven for small modular reactors

- 485 MW plant in Borssele as only nuclear power plant in the Netherlands, its license to operate is set to expire by 2033 according to the *'Kernenergiewet'* – it belongs to the Generation II reactors, built between the 1960s and 1990s
- For Small Modular Reactors (SMRs), a multitude of different designs and concepts exist that have yet to prove their technical / commercial readiness – most advanced versions are constructed in Argentina, Russia and China[3]
- Third generation reactors are being built in Olkiluoto (Finland), Flamanville (France) and Hinkley Point (United Kingdom) at this point

1) KPMG, *Marktconsultatie kernenergie*; 2) Costs based on EPR third generation type reactor (European Pressurised Reactor) third; 3) Fuel price before plant efficiency – price for 1 MWh fuel

Sources: Aurora Energy Research; KPMG; Lucyd Catalyst; DIW; International Atomic Energy Agency

Based on economics and the role of different technologies in the power market, we distinguish four categories of technologies

AURORA

A Dispatchable Prod. Technologies

- Technologies that can freely dispatch to the market and can be characterized by their **levelized costs of electricity** (LCOE)
- Assets are **financed** through the **wholesale market** – they will dispatch against **their marginal costs** and depend on the **absolute height of power prices** to recover their costs

Technologies

- *Biomass*
- *BECCS*
- *Biogas*
- *Gas CCS*
- *Hydrogen*
- *E-methane*
- *Metal fuels*
- *Nuclear energy*

B Storage Technologies

- Technologies that buy power from the market in low price hours and then later sell it again at higher prices – characterized by their **levelized cost of storage** (LCOS)
- Assets are **financed** through the **wholesale market** – they depend on the **spread between high and low-price hours** (not on the absolute level) in order to recover their costs

- *Batteries – Li-Ion*
- *Batteries – Redox-Flow*
- *Compressed Air*
- *Vehicle to grid*

C Demand flexibility Technologies

- *Industrial DSR*

D Other Technologies

Remarks for the following section:

- We show detailed plant characteristics and will include the technologies with 1 MW into the model to test their profitability
- As part of the project, we will determine the capacity of each technology that we assume to be in the power market
  - We present information on expected build-out and / or pilots in order to calibrate at which point in time and how these technologies contribute to the security of supply
- A battery asset will buy power at low prices and dispatch at peak prices
- Technologies in this section are constrained by their duration – they can only supply the amount of power that has previously been stored
  - They will rather provide additional power in hours of high demand, consume power where demand was low before and thus shave peaks

Source: Aurora Energy Research

Lithium-ion batteries provide short-duration flexibility at low cost – increasing number of industrial-size projects realized

AURORA

Description

- Li-Ion batteries have high roundtrip efficiency and are a proven technology to store power for shorter durations
  - Could store for longer durations, but cost increases strongly
  - Also, the longer the duration, the more difficult it is for batteries to capture high-enough spreads
- Industrial scale projects offer durations of up to 4h, for which Li-Ion is highly cost competitive

If the technology is profitable for 4 hours, we may assess it for longer durations

Potential barriers for adoption

- Mineral resources may eventually prove a limiting factor to the widespread adoption of lithium-ion batteries
- Not only the availability, also the extraction of lithium may up for debate: the mining operations associated with extracting lithium are considered dirty and have strong negative environmental impacts, at least on the local level
- Given the cost of Li-Ion rises strongly with duration, the technology is economically limited in the numbers of hours it provides flexibility

Key parameters for 2030

Currencies in real 2020

Parameter	Value	Unit
Lifetime	15	Years
Typical unit size	>100	MW
Cost – CAPEX[1]	720,000	EUR/MW
Cost – Fixed O&M[1]	8,500	EUR/MW/a
Cost – Variable O&M	0.5	EUR/MWh
Round trip efficiency	90	%
Cycles	5,000	-
Discharge duration	4	h

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: Medium - High

- In the Netherlands, several Li-ion projects of smaller scale exist, for instance:
  - AES Netherlands Advancion Energy Storage Array: 10 MW
  - Amsterdam ArenA: 3 MW
- A Li-Ion facility with 48 MW / 50 MWh has been built in Jardelund, Germany, by Eneco in cooperation with Mitsubishi
- Globally, the largest project with 300 MW and 4 hours of duration is the Moss Landing Energy Storage System in California

1) We assess CAPEX and Fixed O&M also for the storage technologies based on Cost/MW in order to make them comparable to the other technologies and to assess need and cost for flexible capacity

Source: Aurora Energy Research

With increasing duration, Redox-flow batteries gain in cost-effectiveness versus Li-Ion but have lower roundtrip efficiency

AURORA

Description

- Redox-flow batteries are a storage technology based on electrochemical processes occurring between a positive and negative electrode
- Power output and storage depth of a redox-flow battery can be scaled independently as the energy is stored in tanks outside the energy conversion unit
- Another feature of this type of batteries is that they do not exhibit significant degradation

Key parameters for 2030

Currencies in real 2020

Parameter	Value	Unit
Lifetime	15	Years
Typical unit size	>100	MW
Cost – CAPEX	1,500,000	EUR/MW
Cost – Fixed O&M	12,000	EUR/MW/a
Cost – Variable O&M	0.5	EUR/MWh
Round trip efficiency	~70-75	%
Cycles	Unlimited	-
Discharge duration	8	h

Potential barriers for adoption

- Redox-flow batteries still achieve lower roundtrip efficiencies, thus they require larger spreads in the power market to achieve profitability
- The initial investment cost for the flow system is quite high – yet, the additional cost for increasing storage depth is lower compared to Li-Ion
- The technology is less standardized and has mostly been proven at a smaller scale

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: Medium

- The EU has recently awarded funds to the MELODY consortium, lead by TU Delft, in order to develop sustainable redox-flow batteries and reduce the costs of the technology
- In Dalian (China), a facility with 200 MW / 800 MWh facility is constructed and planned to be operational by the end of the year which would be the largest operational unit – thus could serve as commercial reference

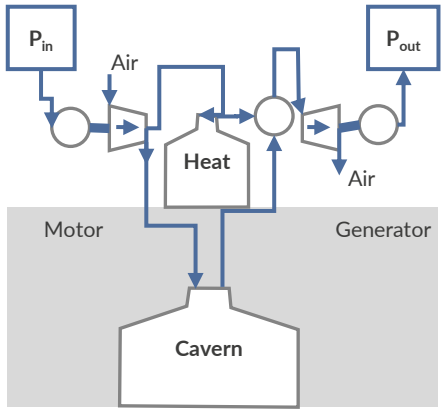
Sources: Aurora Energy Research; IRENA; European Association for Storage of Energy; Fraunhofer ICT; TU Delft; RWE

D-CAES is a proven technology, while pilots for carbon-free A-CAES systems are ongoing – caverns required for storage

AURORA

Description

- A compressed air energy storage system (CAES) is based on air compression and storage in an underground cavern
- Electricity is used to compress air, for an adiabatic plant (A-CAES) the heat of compression is stored separately
- To retrieve the energy, the compressed air is used to generate power in a turbine
- For diabatic plants (D-CAES) systems , additional fuel is used to release power – with H2 as fuel it becomes carbon-free



Depiction of A-CAES plant

Potential barriers for adoption

- In order to construct / install CAES systems, underground caverns are required as storage locations
  - Research is ongoing on whether the Dutch underground is suitable and offers sufficient opportunities for the development of large-scale compressed air energy storage
- A-CAES systems are not yet widespread – the technology still has to prove its commercial potential (while for D-CAES systems several plants have been in operation since >20 years)

Key parameters for 2030

Currencies in real 2020

Parameter	A-CAES	D-CAES	Unit
Lifetime	30	Similar	Years
Typical unit size	~100-500	Similar	MW
Cost – CAPEX	1,900,000	950,000	EUR/MW
Cost – Fixed O&M	20,000	Similar	EUR/MW/a
Cost – Variable O&M	2	Similar	EUR/MWh
Cost – Fuel	0	~65-110[1]	EUR/MWh
Round trip efficiency	65	54[2]	%
Cycles	Unlimited	Similar	-
Discharge duration	~10-15	Similar	h

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: Medium - High

- Corre Energy together with Infracapital is developing a D-CAES plant in Zuidwending, Groningen
  - Capacity of 320 MW, daily dispatch of up to 3-4 GWh
  - Use of hydrogen as fuel for releasing the compressed air – carbon-free
  - Planned to be operational by 2025
- As for A-CAES plants, two 500 MW/5 GWh projects have been announced in California by Hydrostor, offering ~10 h of duration

1) Fuel price for a set-up using hydrogen; price for 1 MWh fuel; 2) Efficiency based on the combined input of electricity and hydrogen

Sources: Aurora Energy Research; European Association for Storage of Energy; TNO; Energeia; Recharge News

Vehicle-to-grid charging still in early phase – implementation depends on readiness of grid and overcoming acceptance roadblocks

AURORA

Description

- Vehicle-to-grid (V2G), or bidirectional charging, means that a car's battery can both charge and discharge at a charging station
- Next to the direction of charging, the (dis-) charging rate can be varied in response to power prices
- If combined with smart meters, vehicles could receive compensation for their peak shaving services

CAPEX based on cost of technical installation for V2G charging at home – going forward likely to become standard for EVs and thus no additional CAPEX required

Key parameters for 2030

Currencies in real 2020

Parameter	Value	Unit
Lifetime	10	Years
Typical unit size	12	kW
Cost – CAPEX	200,000	EUR/MW
Cost – Fixed O&M	0	EUR/MW/a
Cost – Variable O&M	0	EUR/MWh
Round trip efficiency	90	%
Cycles	100–150	#/a
Discharge duration[1]	4	h

Potential barriers for adoption

- Even more so than for regular electric vehicles, range anxiety is a roadblock to consumer acceptance
- Since batteries have a finite number of cycles, customers could be concerned that vehicle-to-grid could shorten a batteries lifetime
  - Pilots show that there is no considerable effect on battery life, as long as it is charged within 20%-80% of battery range
- DSOs will need to prepare for additional grid load and aggregate EVs to effectively provide flexibility from bidirectional charging
- As such, the technical readiness level of V2G is still quite low

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: Low

- At present vehicle-to-grid is virtually non-existent, mainly because the electric cars currently on the market are not suitable for it
- However, Utrecht-based shared car company We Drive Solar and car manufacturer Hyundai have signed an agreement to conduct a large-scale test of bidirectional charging in the Utrecht region
  - By early 2022, some 150 electric shared cars that can feed electricity back into the grid should be driving around in Utrecht
- In July 2021 Fiat and Engine have launched the largest existing pilot project in Turin, Italy with 64 EVs

1) When charging and dis-charging between 20% and 80% of battery storage level, degradation is so low that it can be ignored. Assumes 75 kWh storage depth and 12 kW charging capacity.

Sources: Aurora Energy Research; We Drive Solar; Aston University

Based on economics and the role of different technologies in the power market, we distinguish four categories of technologies

AURORA

A Dispatchable Prod. Technologies

B Storage Technologies

Remarks for the following section:

- Given demand flexibility technologies will not be financed through the wholesale market, we have to assume their capacity exogenously in our modelling
- Thus, we present the magnitude of flexible demand that we have assumed in the Project Base Case alongside information on maturity and potential pilot projects
  - The Project Base Case is a combination of Aurora's Dutch Net Zero scenario that has been aligned with EZK and TenneT based on the PBL's Climate and Energy Outlook, TenneT's Security of Supply Monitor and the Integrale Infrastructuurverkenning 2030-2050
- The demand flexibility technologies will have a certain base demand of power, but are able to contribute to security of supply by adjusting their demand in reaction to price signals

- *Hydrogen*
- *E-methane*
- *Metal fuels*
- *Nuclear energy*

C Demand flexibility Technologies

- Technologies do not supply electricity but can **adjust their demand subject to certain constraints,** e.g. storage size, degradation, consumption patterns
- Assets are **not financed through the wholesale market** – investments mostly made for other purposes (e.g. heating) but assets can contribute flexibility and hence to security of supply

- *Heat Pumps*
- *Hybrid Heat Pumps*
- *Electric Boilers*
- *EV Smart Charging*
- *Industrial DSR*

D Other Technologies

- **Renewable assets** also are characterized by their **levelized costs of electricity** (LCOE) and financed through the **wholesale market**, but **cannot freely dispatch power**
- **Interconnectors** are built based on **socio-economic cost-benefit** analysis – their economics depend on **prices differences** between markets

- *Additional RES Capacity*
- *Interconnection*

1) Based on Aurora's Dutch Net Zero scenario, includes adjustments and alignments made during the project;

Source: Aurora Energy Research

Heat pumps can contribute to security of supply when they can react to power prices and store heat – flex potential rising over time

AURORA

Description

- Heat pumps are an alternative to the ubiquitous gas boilers to heat homes
- Electric heat pumps provide both heat and hot water, eliminating the need for a gas connection
- Heat pumps with storage and the ability to react to prices can decouple heat and power demand and thus provide flexibility
- An average household could shower for two weeks with one full storage cycle of a heat battery

Aurora's modelling approach

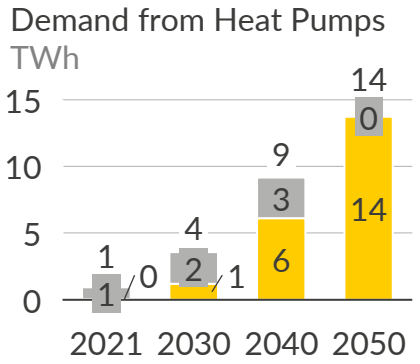
- Aurora's model features a heat-specific electricity demand forecast with seasonal variation
- We model different types of heat pumps: Some heat pumps cannot react to power prices (~2/3 in 2030) and thus not provide flexibility, while we assume the other ~1/3 of heat pumps to be smart by 2030
- Smart heat pumps will react to power prices: they start producing heat when conditions are favorable and store it (e.g. heat battery, hot water cylinder) – reduce their demand when prices and demand from other market participants are high
  - In our modelling, we assume a duration of 2h at full discharging power[1]

Potential barriers for adoption

- Not all heat pumps can flexibly respond to variable power prices and have storage options – retrofitting possible, but will not happen for all units
- Due to high insulation requirements, heat pumps are best suited to newly built homes
- The spread of heat pumps depends on the public – high upfront costs, low awareness and a lack of understanding of costs and benefits might hamper uptake
- Heat pumps could increase the peak demand for electricity, investments in electrical grid infrastructures may be needed

Maturity, Demand Size Netherlands (Project Base Case), Pilots

Commercial Maturity: High



- By 2018, according to CBS 200,000 heat pumps had been installed in the Netherlands
- Over time, the number of heat pumps that can store energy will increase - we expect annual demand of ~2 TWh from these heat pumps by 2030, ~25 TWh by 2050

1) In situation of max heat demand, the battery could provide heat for two hours without any need for power – in other situations much longer. In reality this will also be highly dependent on housing insulation

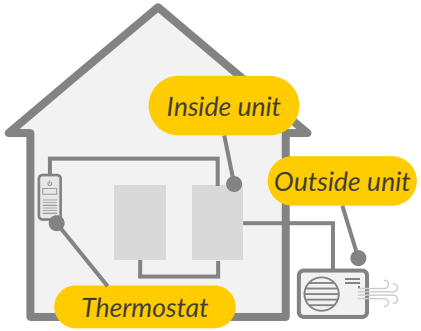
Sources: Aurora Energy Research; TNO; CBS

Hybrid heating systems are an alternative way to decouple heat and power demand – participation depends on alternative fuel price

AURORA

Description

- A hybrid heating system ('hybrid heat pump') is a combination of an electric heat pump and a boiler[1]
- The heat pump uses outside air as a heat source, generated heat is transferred to the central heating system
- The boiler produces additional heat at peak demand moments, when the efficiency of the heat pump drops
- An advantage vs. an all-electric heat pump is that no minimum level of insulation is required, the boiler can always top heat production up



Potential barriers for adoption

- The combination of an electric heat pump and a gas boiler is not CO_2-free – hybrid heat pumps might rather be a transition technology
  - Alternatively, installing a hydrogen boiler and heating with hydrogen as alternative source would be expensive and cost are a main consideration for rapid uptake
- Some existing radiators may not be suited to the lower temperatures (45-55 °C) at which a heat pump works compared to a traditional boiler (60-80 °C)

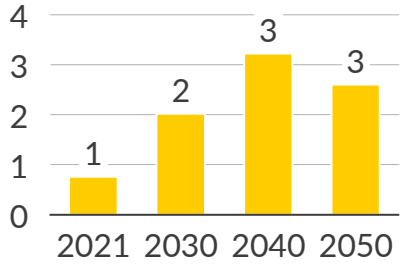
Aurora's modelling approach

- Hybrid heat pumps are bought by households for the primary purpose of heating – thus they do not need to be financed through the wholesale market
- We model hybrid heat pumps like heat pumps on the demand side, compared to normal heat pumps they however have less peak demand
- The hybrid system will optimize its consumption throughout the day (like other smart heat pumps), taking into account the price of the alternative fuel (e.g. clean gas price, price of hydrogen)[2]
- Initially these hybrid systems will mostly run using natural gas, but over time switch towards hydrogen

Maturity, Demand Size Netherlands (Project Base Case), Pilots

Commercial Maturity: High

Demand from Hybrid HPs
TWh



- Low penetration of hybrid heat pumps to date in most markets – 'HR-Hybrid Coalition' (including TenneT) demands for installation of up to 2 million heat pumps (with gas as alternative fuel) by 2030

1) Fuels could be natural gas, hydrogen or the combination of a solar panel and battery; 2) This also depends on the efficiency of the alternative boiler

Sources: Aurora Energy Research; ECN; TNO; Techniek Nederland; II3050

Electric boilers can produce clean and flexible industry heat – activation of the hybrid systems depends on alternative fuel price

AURORA

Description

- Electric boilers can be used to generate heat for businesses
- Industrial applications typically deploy hybrid boilers, which use a boilers with alternative fuel (gas, hydrogen) as a back-up source of heat
- Electricity is used to generate heat when prices are low, the alternative boiler[1] is used in the remaining hours

Aurora's modelling approach

- Like hybrid heat pumps, e-boilers react to power prices by comparing them to the cost of running on their alternative fuel, which serves as the activation cost[2]
  - Over time, more and more boilers in our model will switch from natural gas (activation cost: clean gas price) to hydrogen (activation cost: import price of hydrogen), reflecting the transition to carbon-free industry heat
- We expect more strong growth of direct electricity demand in industry, most of which will arise from the electrification of heat – by 2050, ~3.6 GW of e-boilers to be in the system and provide flexibility in industry heating

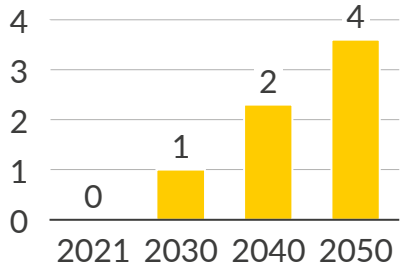
Potential barriers for adoption

- If gas is used as the alternative power source (at least initially), the system would still lead to carbon emissions
- Cost would be the main hurdle for fast and widespread adoption of electric boilers in industry
  - Replacing the boilers by hydrogen-based alternatives would additionally add to this factor

Maturity, Demand Size Netherlands (Project Base Case), Pilots

Commercial Maturity: High

Capacity of E-Boilers
GW



- Electric boilers are a new category in the SDE++ subsidy scheme
- In the autumn round of 2020, nine projects received subsidies, totalling 249 million euros for a capacity of 310 MW
- Some projects with subsidy locked in:
  - USG Industrial Utilities (Chemelot), industrial boiler: 20 MW
  - Vattenfall, district heating in Amsterdam, Almere and Diemen: 50 MW each

1) Also for district heating systems the alternative power source would be a gas boiler, as the efficiency of e-boilers is too low to push out baseload sources like CHPs; 2) Boiler efficiency taken into account

Sources: Aurora Energy Research; PBL; Energeia; RVO

Electric vehicles will increasingly offer demand flexibility, as penetration of EVs and availability of smart charging rises

AURORA

Description

- An electric vehicle (EV) is propelled by an electric motor, using power stored in a lithium-ion battery
- EVs are charged at a dedicated charging station: at home, at work (e.g. corporate fleets) or at a public charging point
- The driving range varies, but lies between 150 and 400 km for passenger cars
- Besides cars, there are also electric (mini-) buses in operation

Aurora's modelling approach

- Aurora's model takes annual demand specific to smartly charging EVs as input, which accounts for quarterly variations: for instance, more travel during the summer due to vacation
- Part of this demand is flexible ('smart EVs'), part is inflexible – increasing share of smart EVs over time
  - Smart EVs observe the wholesale power price and optimize charging cost to the consumer, leveraging the duration of their battery of ~4-5h[1]
  - They are subject to the following constraints: EVs cannot charge at the same time as driving (charging availability) and EVs must have sufficient charging levels to drive

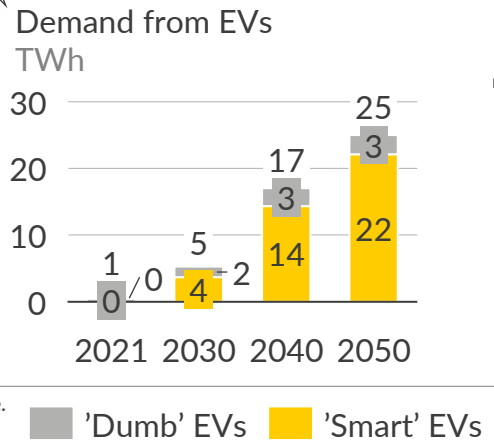
Potential barriers for adoption

- Total cost of ownership (TCO) of EVs still much higher than of petrol cars - pricing of EVs and thus adoption happens outside of wholesale market
- Infrastructure for charging (i.e. charging point density) needs to be available for widespread use
- Range anxiety by consumers poses an acceptance problem – for EVs in general, but potentially also for smart charging
  - Consumers could be sceptic of postponing the charging of their car for grid purposes
- Disposal of batteries as potential environmental concern

Includes heavy vehicles, electric buses etc.

Maturity, Demand Size Netherlands (Project Base Case), Pilots

Commercial Maturity: Medium



- Penetration of car market with EVs expected to pick up fast – many new cars will be technically ready for smart charging
- NewMotion, owned by Shell, has been licensed in the Netherlands to provide grid balancing services through smart charging – slowing the charging rate of a fleet of vehicles when frequency is too low and vice versa

1) This means the battery charges in ~4-5 hours at an average charger. However, this allows to drive much longer than that on average.

Sources: Aurora Energy Research; New Motion

Industrial flexibility is a potentially potent source of demand-side response in the Netherlands that can be activated at higher prices

AURORA

Description

- Industrial demand-side response (DSR) is a mechanism whereby end-users adjust their demand based on price signals
- Dutch industry is already contributing to balancing the grid
- Currently, only ~20% of the theoretical potential is actively participating in the market
- Companies with substantial electricity demand and non-continuous processes are best placed to participate in the DSR market

Aurora's modelling approach

- Demand can be reduced when a certain activation power price is reached – i.e. the price is high enough to compensate for shifting / shedding production
  - This activation price differs between industries
- For the timeline of industrial DSR, we relied on external sources – we enter an exogenous timeline in our model based on market analysis, not allowing the technology to change its capacity
- DSR can only be active a limited amount of hours per year

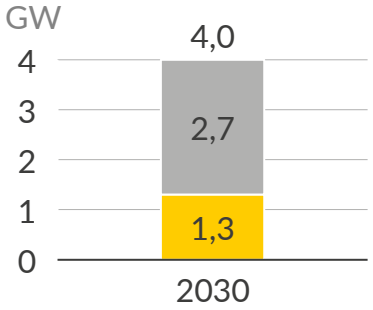
Potential barriers for adoption

- Low awareness of the (economic) potential of DSR for industry seems to hinder participation
  - Comprehensive information and easy regulatory / administrative implementation could reduce hurdles for industrial players
- According to DNV, 40% of the potential for DSR comes at a cost of over 3,000 EUR/MWh, the current maximum price on the day-ahead market
  - This likely sets un upper ceiling on the potential that will eventually be unlocked

Maturity, Demand Size Netherlands (Project Base Case), Pilots

Commercial Maturity: High

Industrial DSR Capacity



- By 2030, the theoretical potential of DSR in the Netherlands is expected to be ~4 GW
- We expect up to 1.3 GW of industrial DSR to regularly and simultaneously participate in the market
  - Variable cost for activation start at 67 EUR/MWh, but quickly rise to over 800 EUR/MWh, final capacities to come online at 2,000 EUR/MWh

Active DSR Remaining Potential

Sources: Aurora Energy Research; DNV GL; TenneT; Strategy &

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AURORA

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- Technologies that can freely dispatch to the market and can be characterized by their **levelized costs of electricity** (LCOE)
- Assets are **financed** through the **wholesale market** – they will dispatch against **their marginal costs** and depend on the **absolute height of power prices** to recover their costs

Technologies

- *Biomass*
- *BECCS*
- *Biogas*
- *Gas CCS*
- *Hydrogen*
- *E-methane*
- *Metal fuels*
- *Nuclear energy*

B Storage Technologies

C Demand flexibility Technologies

- *Industrial DSR*

Remarks for the following section:

- For RES assets and interconnection capacity, we have to assume an existing buildout timeline to cater to the reality of these assets already being in the market
  - The Project Base Case is a combination of Aurora's Dutch Net Zero scenario that has been aligned with EZK and TenneT based on the PBL's Climate and Energy Outlook, TenneT's Security of Supply Monitor and the Integrale Infrastructuurverkenning 2030-2050
- We can, however, assess the economics of marginally adding more assets
  - For RES assets, this will be standard model output
  - For interconnection, we will calculate the interconnector rents
- The model curtails generation from wind and solar when RES production exceeds demand to avoid negative prices and balance supply (taking into account inter-country flows)

D Other Technologies

- **Renewable assets** also are characterized by their **levelized costs of electricity** (LCOE) and financed through the **wholesale market**, but **cannot freely dispatch power**
- **Interconnectors** are built based on **socio-economic cost-benefit** analysis – their economics depend on **prices differences** between markets

- *Additional RES Capacity*
- *Interconnection*

Source: Aurora Energy Research

Interconnection with other countries can contribute to security of supply in Netherlands – further buildout until 2050 expected

AURORA

Description

- The European electrical grid supplies power at a frequency of 50 Hz and is operated by TSOs, which together form ENTSO-E[1]
- The Netherlands became a net exporter in 2020 – net exports to UK and Belgium and net imports from Norway and Denmark – balance with Germany[2]
- European interconnection is expected to increase, e.g. NordLink, between Germany and Norway, operational as of May 2021

- Demand, outages and RES generation are imperfectly correlated across countries – additional interconnection can contribute to security of supply
- Also a mitigating effect on price volatility is expected

Potential barriers for adoption

- International cooperation is required to complete interconnection projects, which usually leads to long lead times
- Politics need to be closely considered – dependance on other countries can be a contentious topic
- The closer the area of RES production is located to the Netherlands, the closer the RES production patters are correlated – reduces contribution to security of supply

Key parameters for 2030

Currencies in real 2020

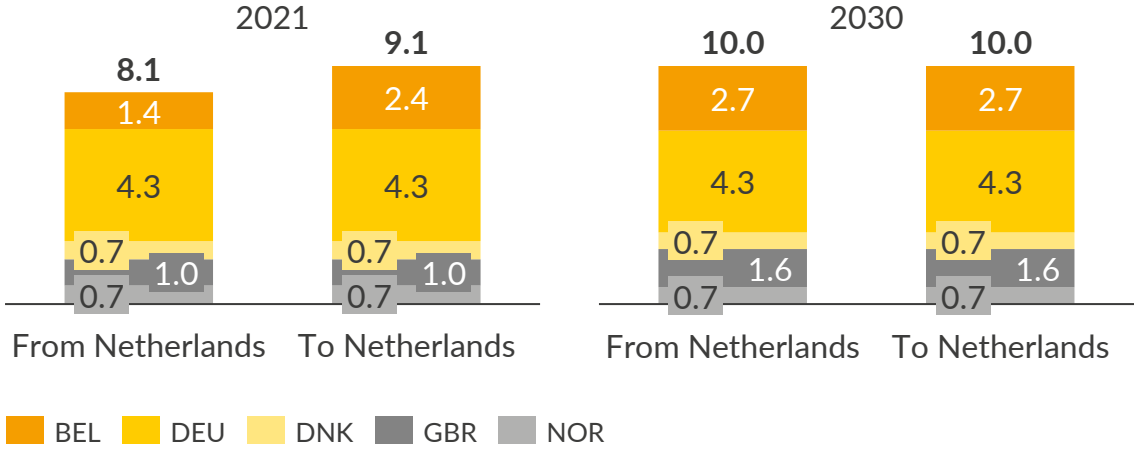
High CAPEX for converter stations – length of connection not main cost driver

Parameter	Value[3]	Unit
Typical capacity	~500 – 2,000	MW
Length	~100 – 1,000	km
Cost – CAPEX	~750,000 – 1,500,000	EUR/MW
Cost – Fixed O&M	~4,000 – 17,000	EUR/MW/a

We propose to model interconnector economics by assessing when the interconnectors are marginal and taking the price delta between the connected countries for these hours

Capacities in aligned Project Base Case[4]

GW



1) European Network of Transmission System Operators for Electricity; 2) Based on physical flows in 2020; 3) Ranges based on cost data from ENTSO-E on select interconnection projects, e.g. including COBRA cable, North Sea Link; 4) Based on TYNDP 2020 for concrete projects until 2030, after 2030 based on System Needs analysis and historical comparison of system needs versus buildout

Sources: Aurora Energy Research; ENTSO-E; Statnett

Offshore wind buildout is expected to grow strongly by 2050 – additional capacities in North Sea to be explored

AURORA

Description

- Offshore wind is an important source of renewable power in the Netherlands
- The government pipeline runs until 2030 and adds up to 11 GW
- Offshore wind buildout has been realized through zero-bid tenders since 2017
- Extra areas in the North Sea need to be designated with sufficient space for an additional 27 GW offshore wind by 2050

Key parameters for 2030

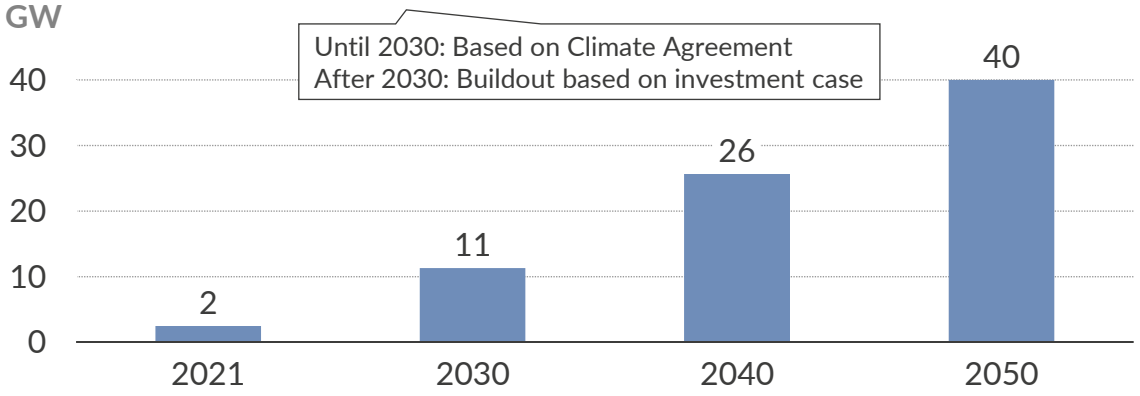
Currencies in real 2020

Parameter	Value	Unit
Lifetime	25	Years
Typical unit size	700	MW
Cost – CAPEX	1,742,000	EUR/MW
Cost – Fixed O&M	48,000	EUR/MW/a
Cost – Variable O&M	2	EUR/MWh
Average load factor	49.1	%

Potential barriers for adoption

- Weather-dependent power generation from wind will place increasing demands on grid infrastructure – otherwise congestion might arise in peak wind production hours
- Extensive buildout of offshore wind impacts nature conservation and fishing.

Capacities in aligned Project Base Case



Sources: Aurora Energy Research; Rijkswaterstaat

While 5 GW of onshore wind buildout has already been realized, newbuilds are facing additional hurdles

AURORA

Description

- Like their offshore counterparts, onshore wind turbines transform the kinetic energy in air motion into electricity
- Onshore wind buildout is planned in the Regional Energy Strategies (RES), in which 30 regions plan their solar and onshore wind buildout
- The latest Monitor Wind on Land found that an additional 2,488 MW onshore wind could be realized by 2023

Key parameters for 2030

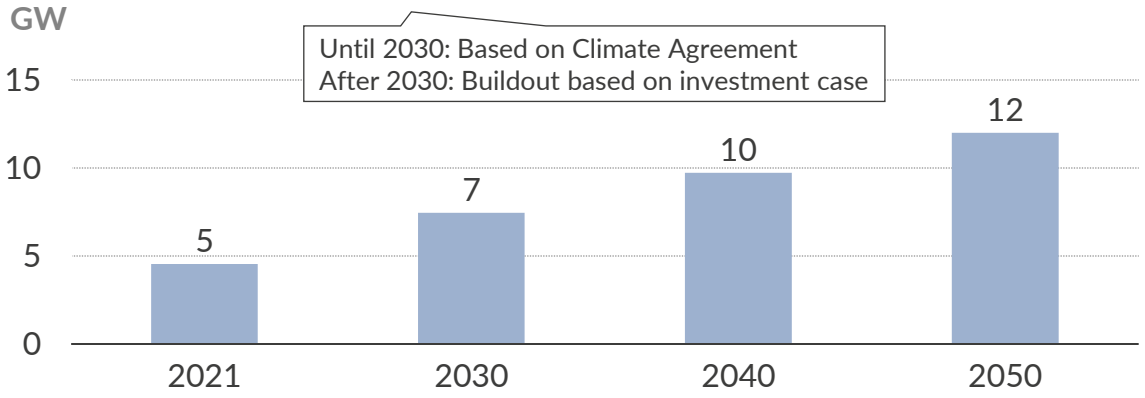
Currencies in real 2020

Parameter	Value	Unit
Lifetime	25	Years
Typical unit size	120	MW
Cost – CAPEX	1,073,000	EUR/MW
Cost – Fixed O&M	51,000	EUR/MW/a
Cost – Variable O&M	2	EUR/MWh
Average load factor	36.5	%

Potential barriers for adoption

- Like in many countries, build-out of onshore wind in the Netherlands is hindered by not-in-my-backyard (NIMBY) concerns
  - While consumers demand green power, there is low acceptance for wind turbines close to the own property
- Wind turbines impact birds and bats – habitats have to be considered during planning

Capacities in aligned Project Base Case



Sources: Aurora Energy Research; Rijksoverheid

Strong increase in solar capacity expected – public preferences are leaning towards rooftop panels

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Description

- Solar panels produce an electrical current through light absorption
- Together with onshore wind, solar buildout is planned in the Regional Energy Strategies
- While households cannot access the subsidy regime SDE++, rooftop solar can profit from the *salderingsregeling*, allowing them to sell part of their power to the grid
  - Starting 2023 the program is slowly phased out until 2031
- The public preference is for rooftop panels

Key parameters for 2030

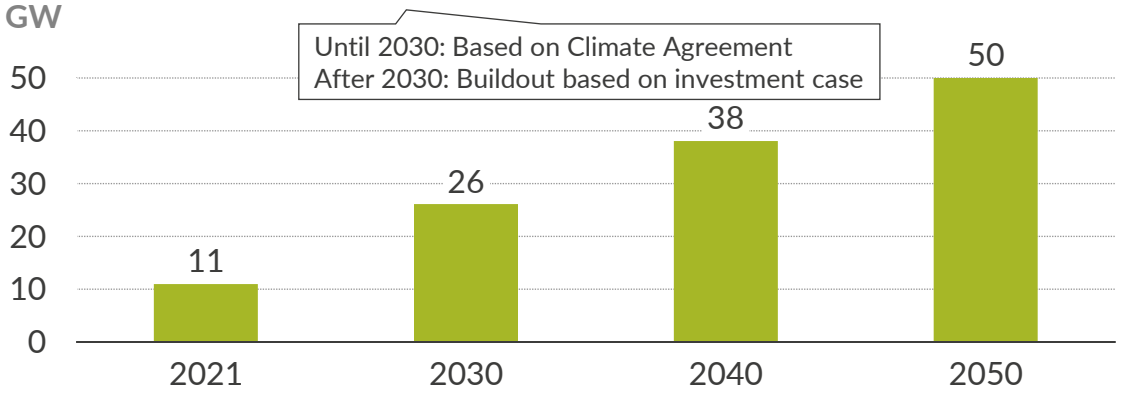
Currencies in real 2020

Parameter	Value	Unit
Lifetime	30	Years
Typical unit size	20	MW
Cost – CAPEX	447,000	EUR/MW
Cost – Fixed O&M	12,000	EUR/MW/a
Cost – Variable O&M	0	EUR/MWh
Average load factor	11	%

Potential barriers for adoption

- Based on the 35 TWh of green power production by 2030 as aligned in the Climate Agreement, Netbeheer Nederland has pointed towards grid connection all these new RES assets as a potential hurdle that might lead to delays
- The use of arable land for solar panels might be subject of increased resistance
- High demand for materials for the manufacturing of solar cells in the short term and production of hazardous waste from old solar panels - infrastructure to recycle end-of-life solar panels needs to be developed

Capacities in aligned Project Base Case



Sources: Aurora Energy Research; Netbeheer Nederland

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Aligned phase out of thermal capacities by 2050 in Base Scenario leads to an emissions-free power system in the Netherlands

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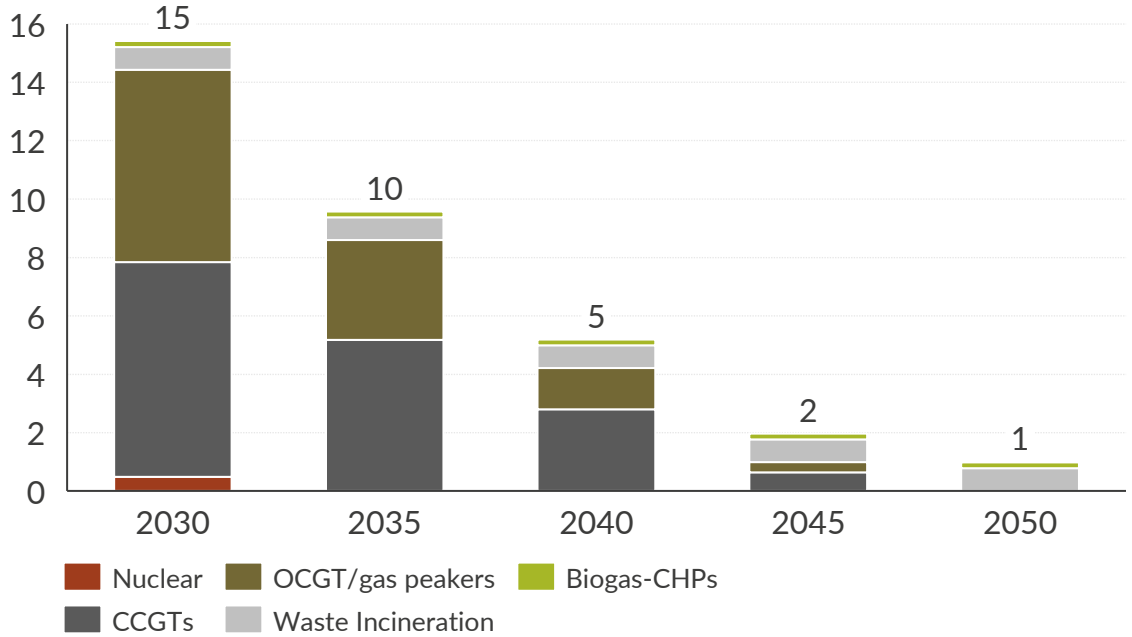
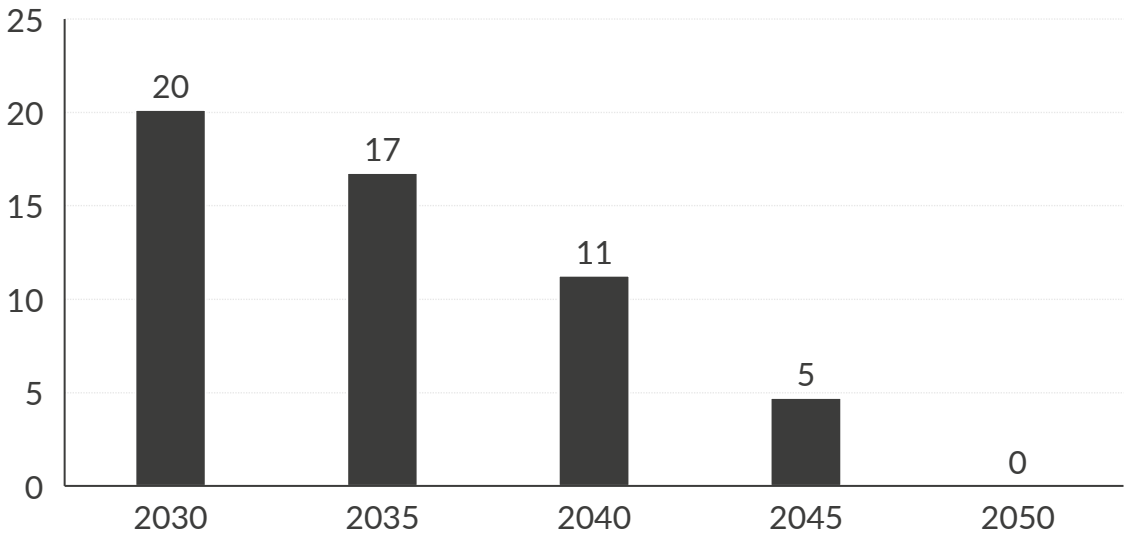
Thermal capacities over time
GW



CO_2 emissions over time[1,2]
Mt



Comments

- In our project base case, of ~15 GW thermal capacity in 2030, ~14 GW are carbon-emitting gas assets
  - These are phased out, such that only ~4 GW of gas plants are left in 2040, and they are completely phased out by 2050
  - Capacity drop in gas assets results from a combination of plants running out of lifetime and capacity restrictions to meet CO_2-targets

Comments

- With the phase-out of gas, carbon emissions in the base case drop by 50% until 2040 in the project base case – power system would be entirely emission-free by 2050
- In 2030 emissions are higher in our model than PBL's estimate for the Climate Agreement, primarily due to our higher electricity demand (113 TWh vs ~130 TWh) because of further electrification in other sectors

1) Assumes waste incineration uses CCS starting 2030; 2) includes emissions from heat produced by CHPs

Source: Aurora Energy Research, PBL

In our Base Scenario there is a large increase of renewables post 2030 – similar development for flexible demand technologies

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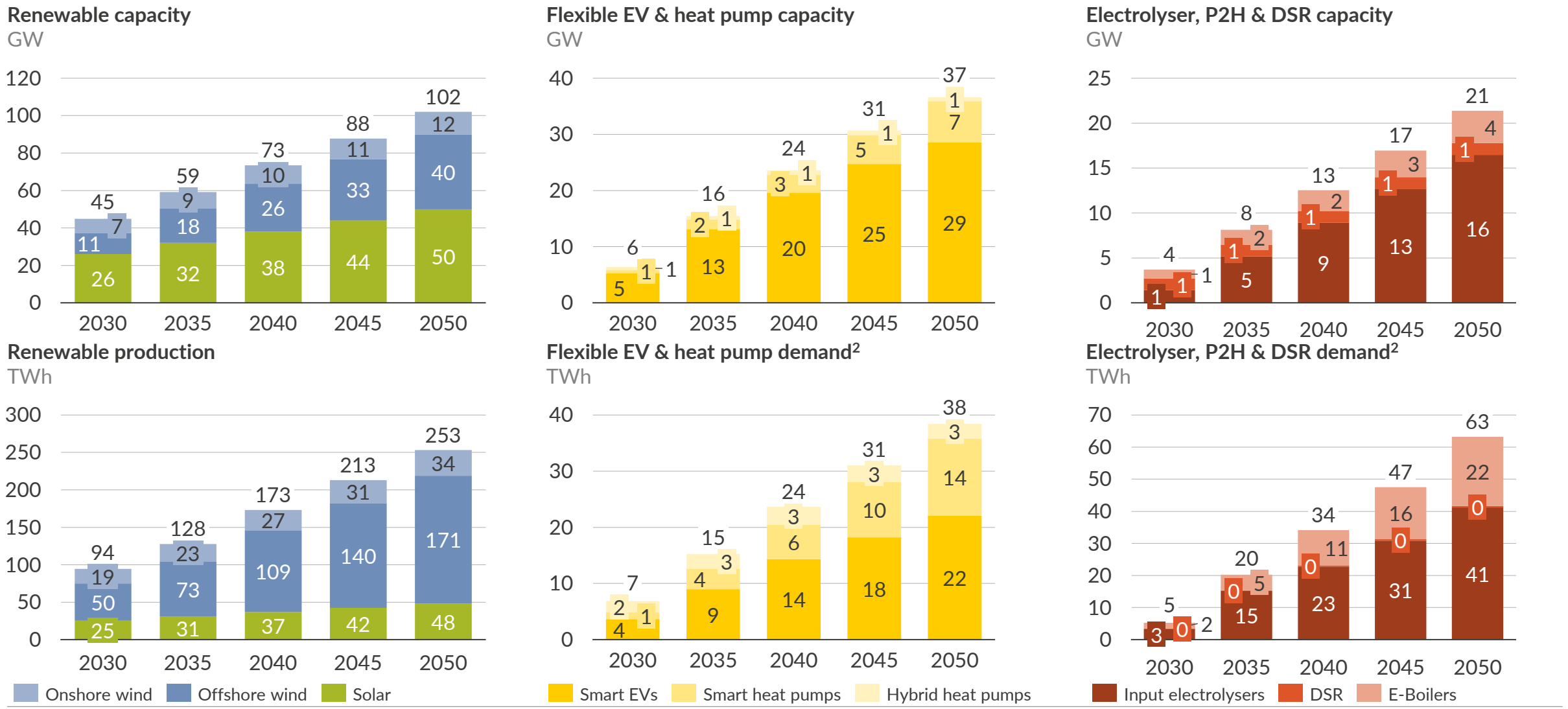

1) By 2030 we expect no batteries to operate in the wholesale market on a large scale, yet they might already be active in imbalance markets; 2) Demand from hybrid heat pumps, electrolysers, P2H and DSR will differ between weather years and technology mixes, as they respond to prices materializing in the power market

Source: Aurora Energy Research

The transition to 'Net Zero' is expected to be accompanied by lower gas and coal prices and higher carbon prices

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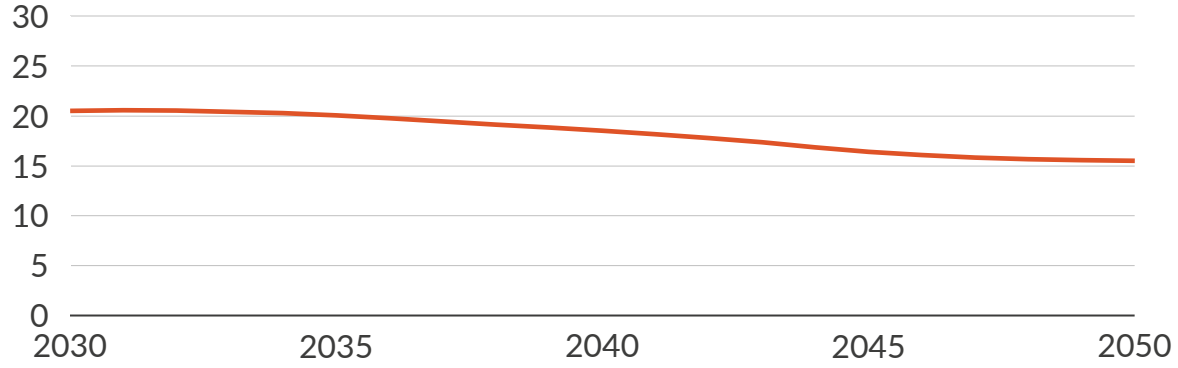
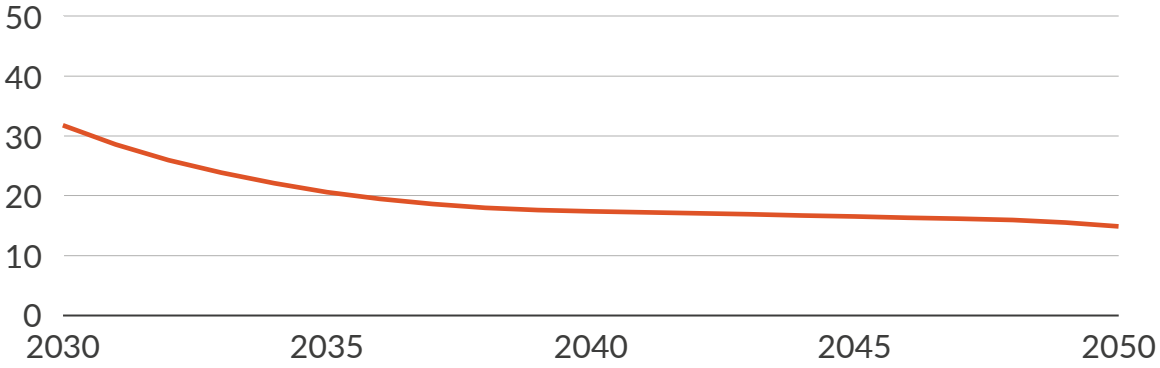
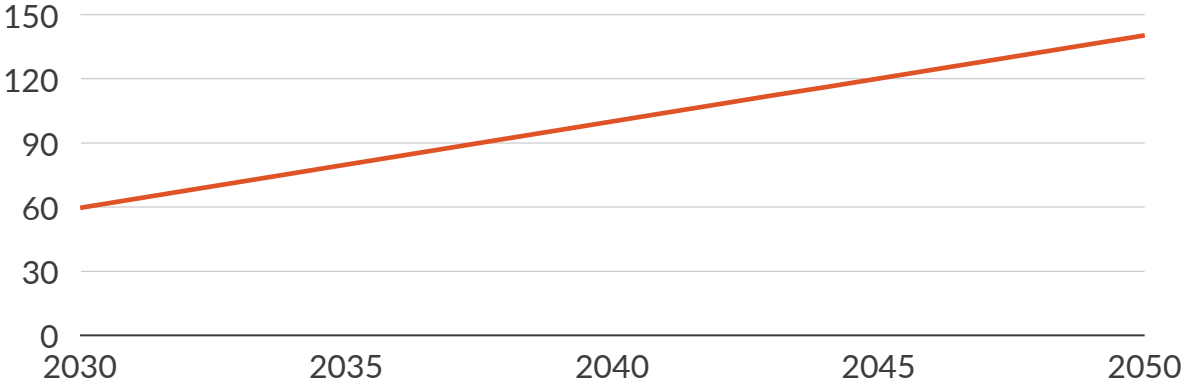
Gas prices
€/MWh (real 2020)



Coal prices
€/tonne (real 2020)



Carbon prices
€/tCO_2 (real 2020)



Net Zero

Aurora's Net Zero price forecast:

- In our Net Zero analysis, the gas price is expected to be around €21/MWh by 2030, driven by coal-to-gas switching and rising global LNG demand. From 2030 onwards prices start to decline, falling to €16/MWh by 2050
- This trend is due to Asian gas demand falling with growing renewable penetration, which drives down the marginal cost of LNG shipments to Europe
- The coal price is expected to plummet to €20/tonne by 2035 as coal is phased out of power, and only the cheapest producers stay online
- We assume a rise in carbon prices to €140/tCO_2 by 2050, reflecting the required marginal CO_2 abatement across most sectors to decarbonise

Sources: Aurora Energy Research, EIKON

Hydrogen supply consists of domestic green and blue as well as imported hydrogen – green imports from North-Africa price-setting

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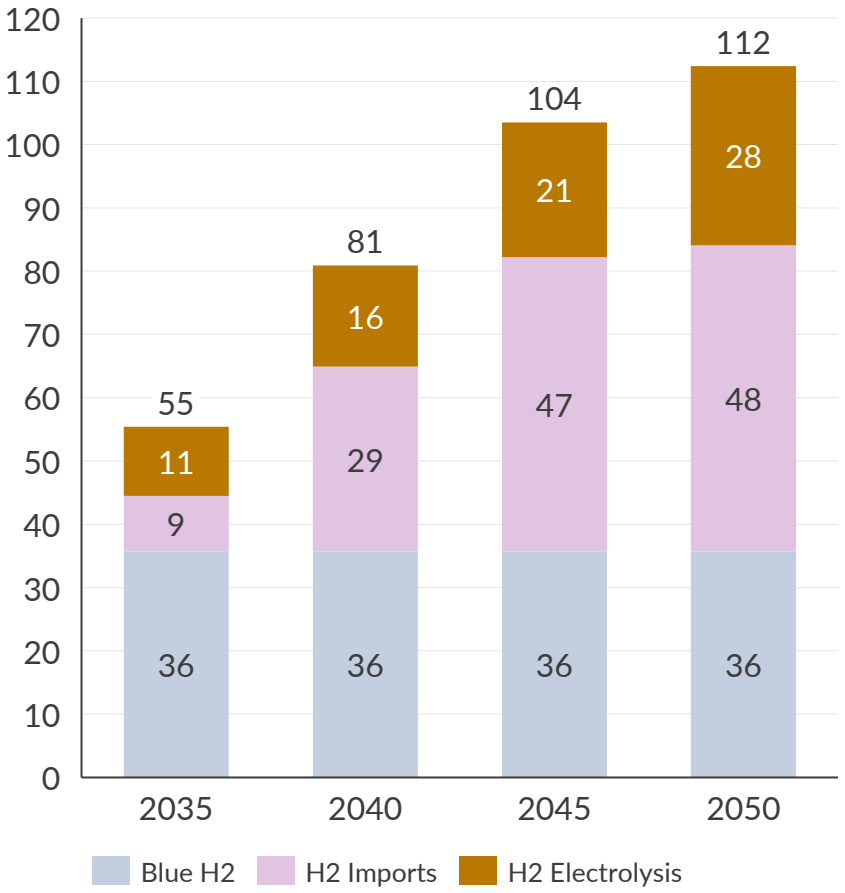
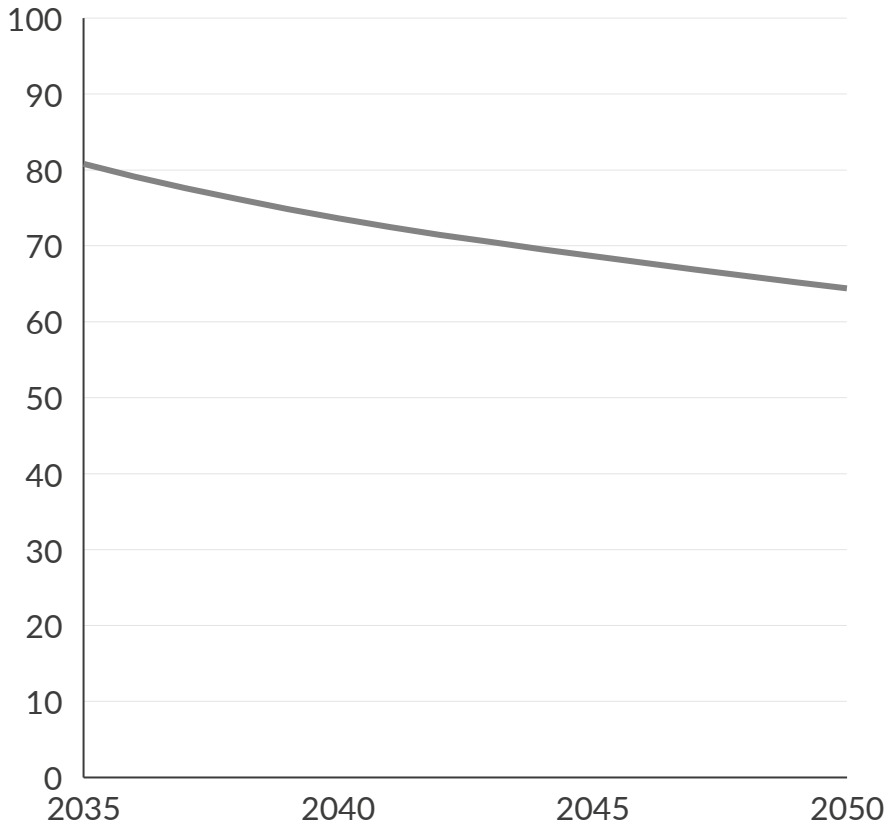
Hydrogen production mix
TWh H2



Hydrogen Price
€/MWh



Comments

- In our model, there is a specific hydrogen module allowing for a hydrogen price to form
  - Takes into account hydrogen demand, marginal cost of H2 plants and electrolyser dispatch in power market
- Hydrogen is imported on a cost basis – in the 2040s in the large majority of hours, imported hydrogen is price setting, thus the impact of blue H2 and H2 electrolysers on hydrogen price is limited
- In 2050, ~16 GW of hydrogen electrolysers are installed, demanding ~41 TWh of power to produce hydrogen

Note: Based on Technology Mix 1, Full Security of Supply scenario

Source: Aurora Energy Research

Due to interconnection to neighbouring countries, developments there need to be taken into account in our Base Scenario

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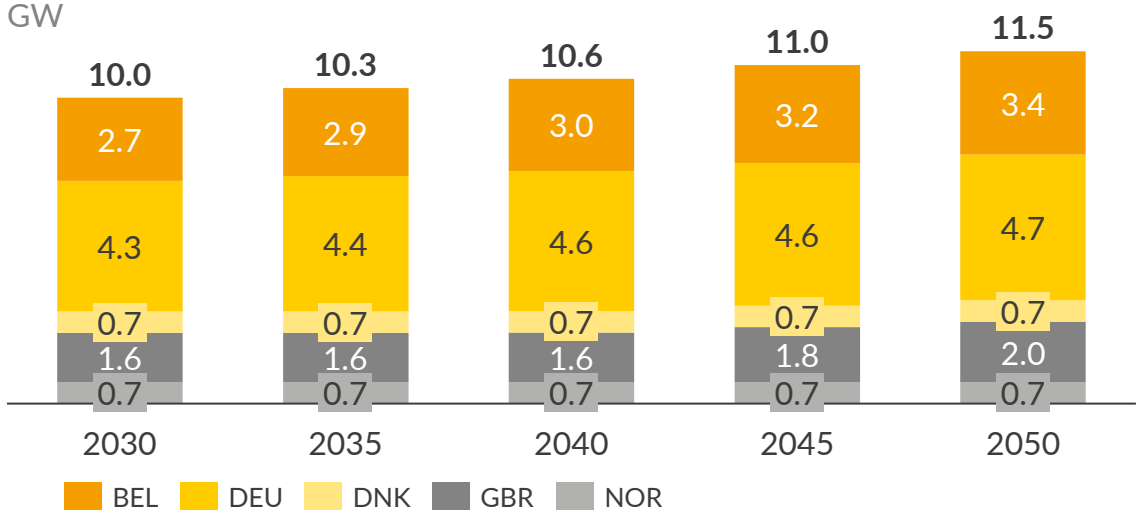
Interconnection capacity Netherlands until 2050[1]

GW



Comments

- The Netherlands are highly interconnected, with up to 12 GW of interconnection by 2050
  - Direct interconnection capacity with Germany and Belgium
  - Interconnected overseas with Denmark, Great Britain and Norway
- Thus, developments in other countries are highly relevant to business cases of technologies (see right-hand side)

Contrary to Germany and Belgium, we have assumed no batteries for the Netherlands in our base case – this is to ensure a level playing field

Developments in key neighbouring countries

Germany

- Nuclear phases out by 2023, lignite is phased out by 2030 and hard coal by 2035
- Gas plants are mostly phased out by 2045 and partially replaced by hydrogen CCGTs and OCGTs
- Renewables are expected to more than triple by 2050 compared to 2021
- Batteries are already part of the mix in 2021 as households combine rooftop solar with home batteries, and are expected to be further build out towards 2050

Belgium

- Nuclear phases out by 2025 and all coal is already closed since 2016
- Gas plants replace nuclear in the 2020s and 2030s, but are converted or replaced by hydrogen plants
- Renewable build out is limited due to a relatively small sea surface and high population density
  - For onshore and offshore wind, maximum capacity is estimated at 9 GW and 8 GW respectively
  - Solar PV is less limited in potential, as it faces less NIMBY issues and rooftop potential is large
- Batteries growth is slower to take off than in Germany, but grows faster to accompany the big roll out of solar

1) Interconnection to and from the Netherlands

Source: Aurora Energy Research

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Levelized Cost of Energy of Dispatchable Production Technologies in Project Base Scenario 2030

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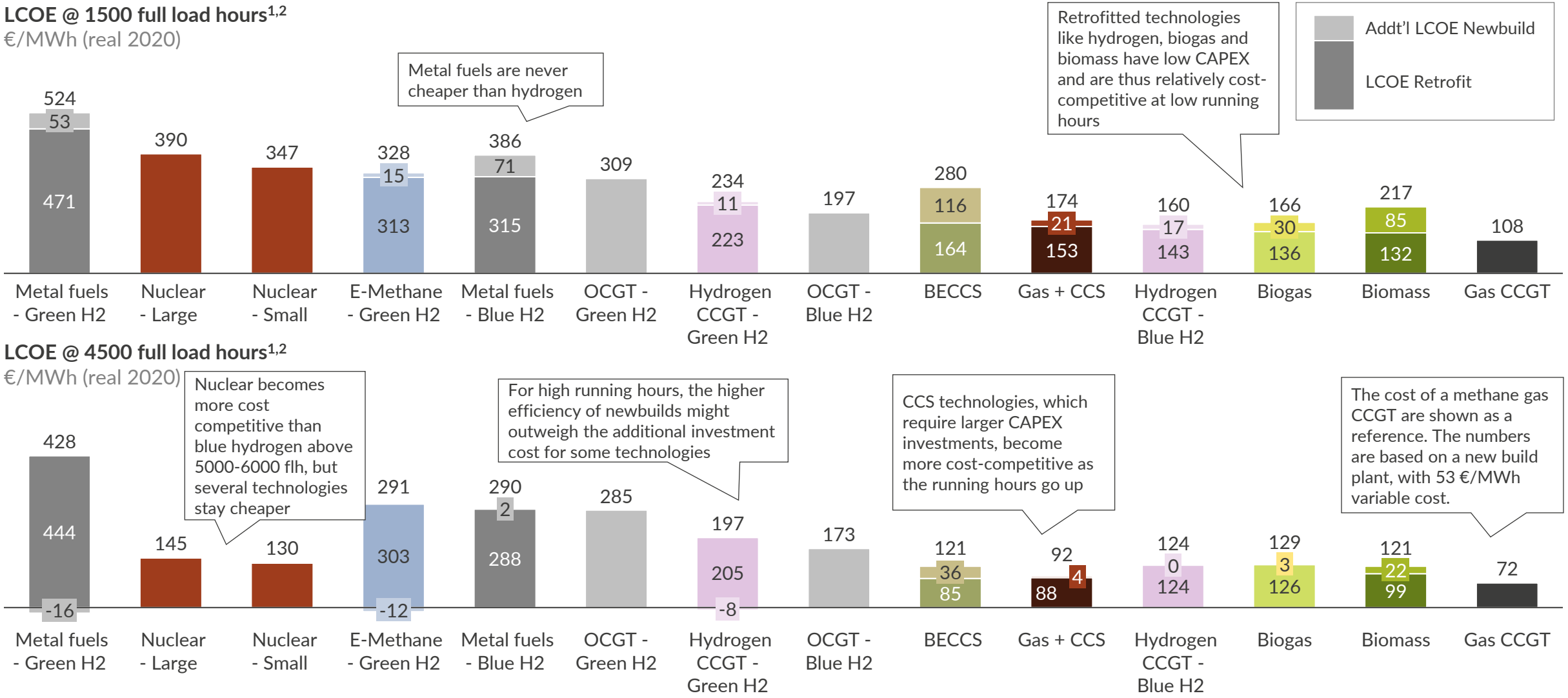
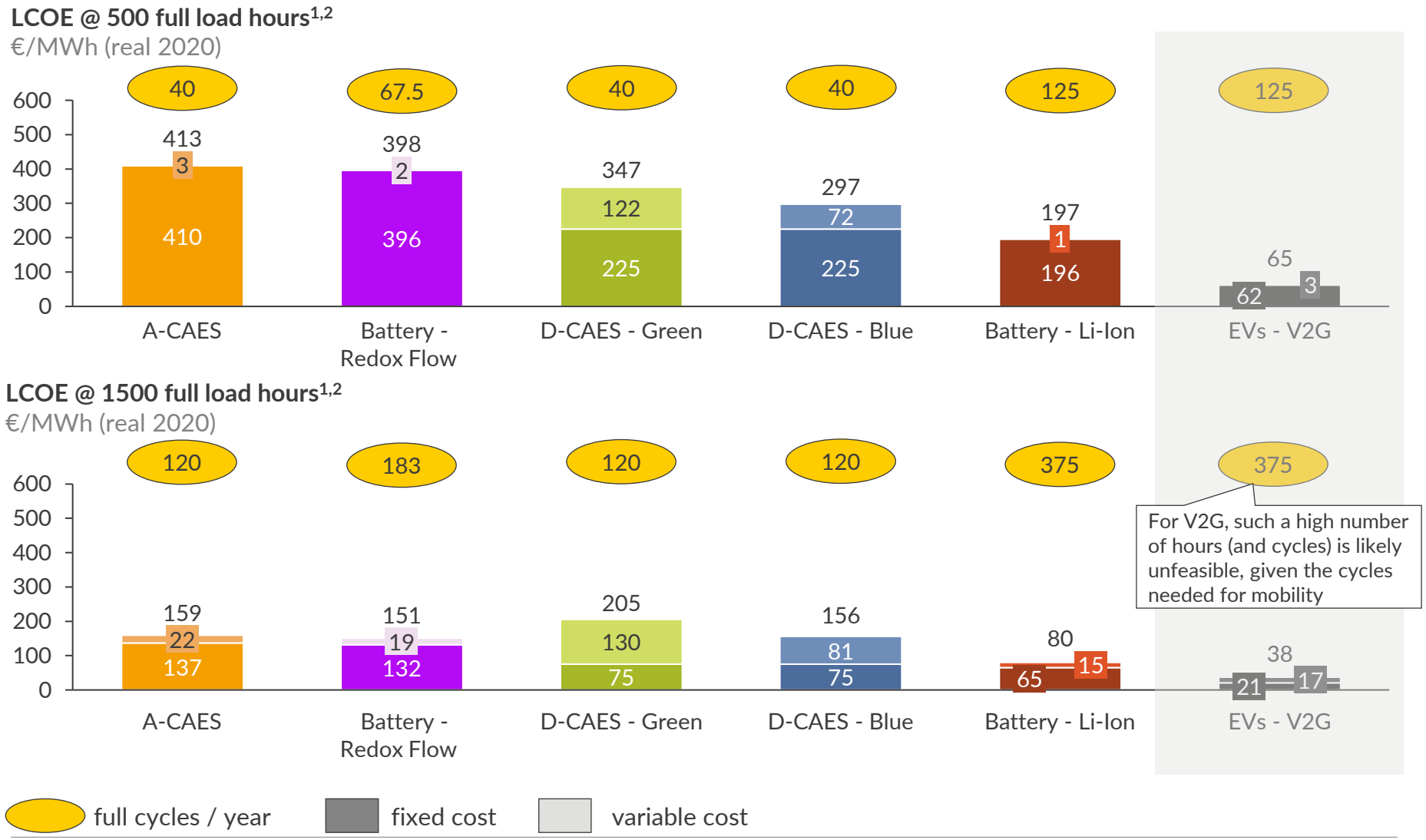


Note: We assume a cost of capital (WACC) of 9%; 1) Does not include costs for ramping; 2) Most gas CCGTS run 3,000 – 5,000 hours in 2030, 1,500 – 2,000 hours in 2040

Source: Aurora Energy Research

Levelized Cost of Energy of Storage Technologies in Project Base Scenario 2030

AURORA



Note: We assume a cost of capital (WACC) of 9%; 1) Does not include costs for ramping; 2) Discharging hours

Source: Aurora Energy Research

Comments

- The cost of electricity output for storage is more complicated to calculate than for other technologies, as the costs are dependent on the price of electricity used for charging the storage
- In the graph the average electricity price for the lowest 500 hours (1 €/MWh) and the lowest 2000 hours (13 €/MWh) in 2030 was used as a proxy for the price of input electricity
- The electricity price corrected with the efficiency, the variable O&M and the hydrogen fuel cost for D-CAES together give the variable cost
- Because of differences in storage depth of technologies, the amount of full cycles per year differs for a given amount of full load hours

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Gap to Profitability in Project Base Scenario 2030 – Best in class technologies

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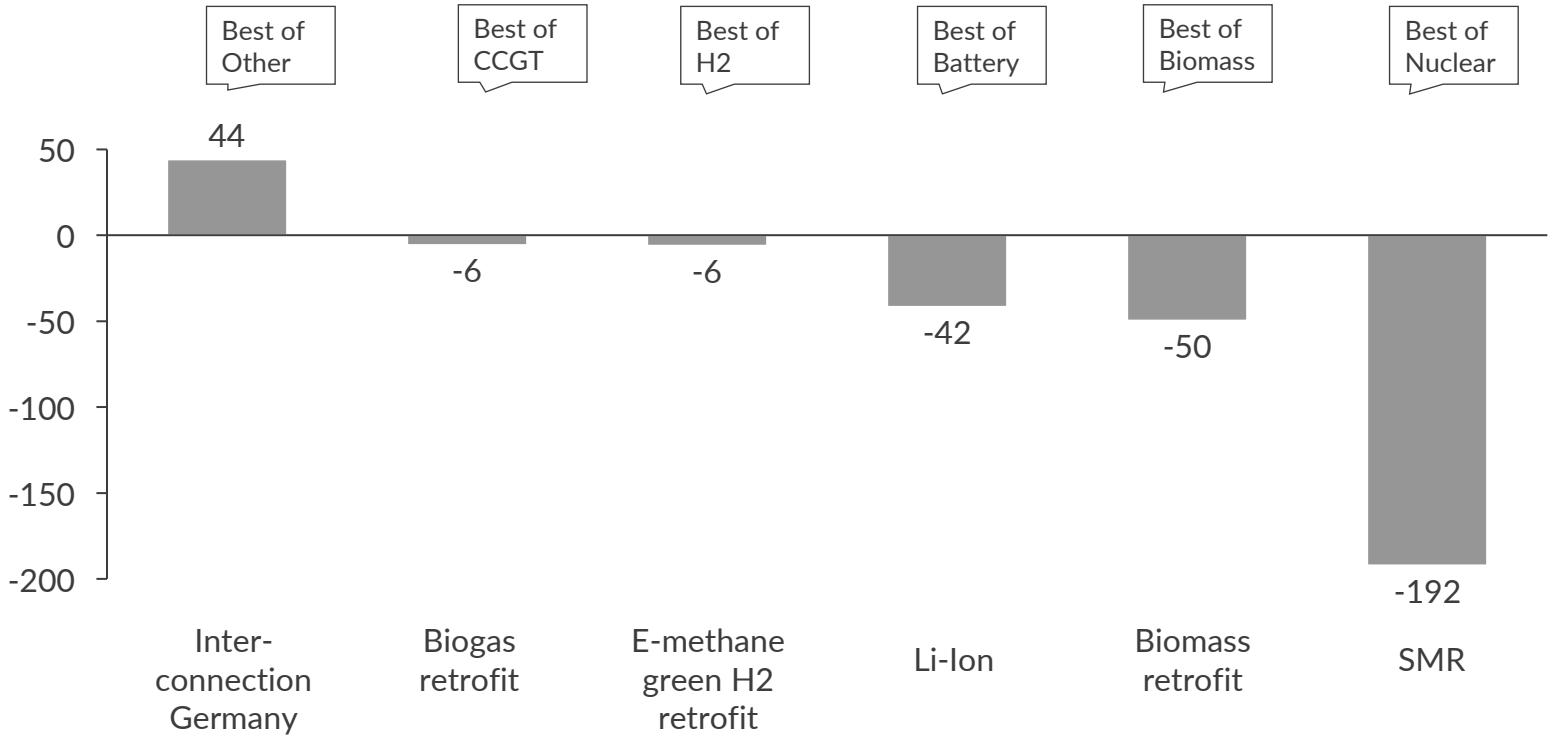
BASE CASE

Gap to profitability 2030 – Best in class technologies
€/kW (real 2020)



	Inter-connection Germany	Biogas retrofit	E-methane green H2 retrofit	Li-Ion	Biomass retrofit	SMR
Run hours (h)	4,808	15	6	686	225	7,405
SRMC (€/MWh)	-	128	315	69	87	23

Comment

- We have assessed the technologies in our 2030 Project Base Scenario on a 1 MW basis
  - Based on power prices and demand, assets will sell power on the market
  - Capacities of other technologies (e.g. RES buildout) have been aligned within project team
- Most technologies have rather significant gaps to profitability in 2030
  - Interconnection with Germany as only profitable technology for 2030
  - Technologies using retrofitted CCGTs have small gaps to profitability, as little capital investment is needed
  - E-methane performs better than hydrogen only with very low running hours
  - Li-Ion operates as best-in-class battery – relatively low capital costs and short duration allow it to capture spreads effectively
  - Nuclear has very significant gap to profitability, as RES lead to many low-price hours

Note: We assume a cost of capital (WACC) of 9%

Source: Aurora Energy Research

Economics of technologies in project base scenario 2030 – Best in class technologies

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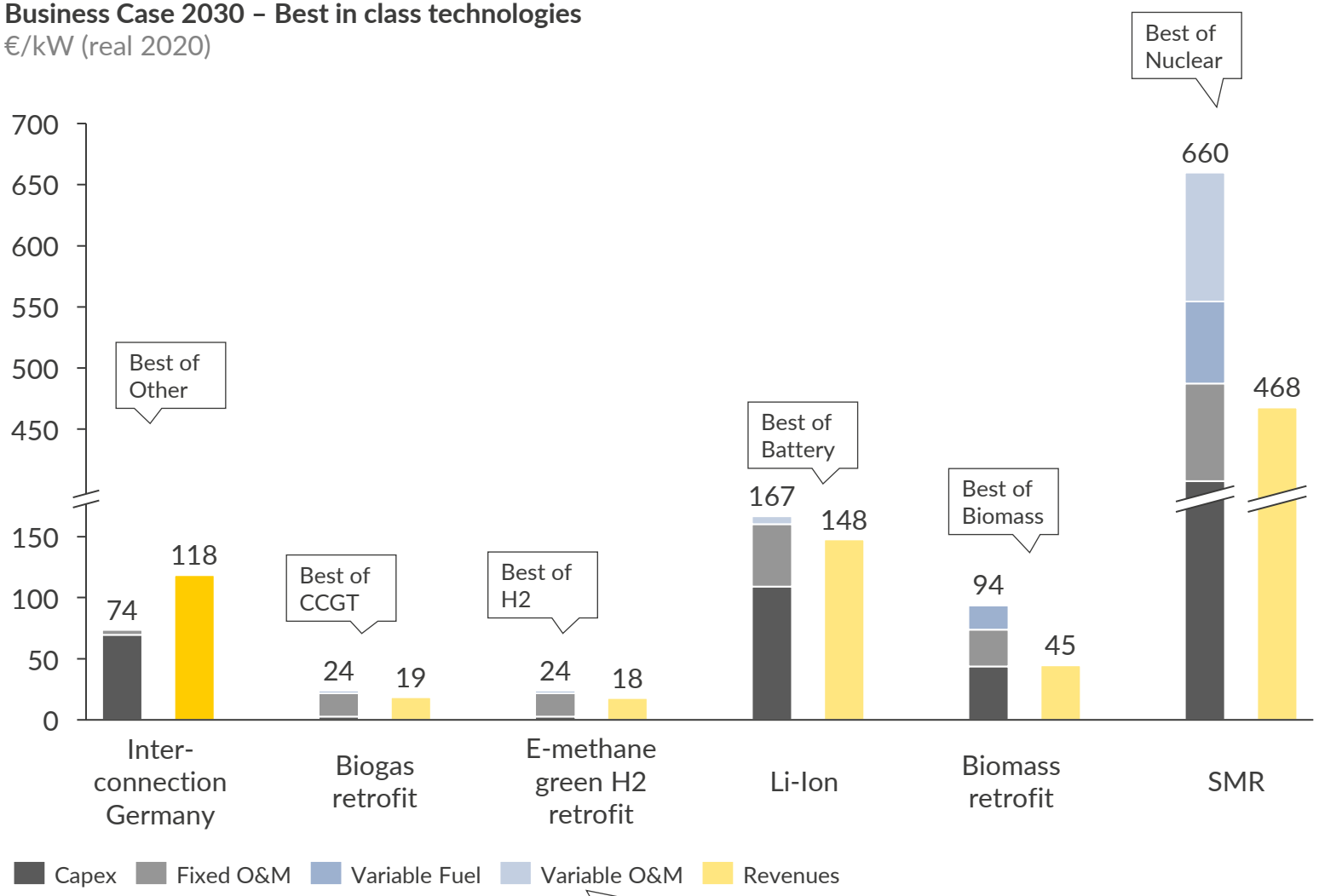
BASE CASE

Business Case 2030 – Best in class technologies
€/kW (real 2020)



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Note: We assume a cost of capital (WACC) of 9%

Source: Aurora Energy Research

Besides the Project Base Scenario we created sensitivities regarding commodity prices and availability of flex capacity

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Scenario	Description	Best-performing technologies
Project Base scenario	▪ Base scenario, as aligned with EZK & TenneT ▪ 2030 prices: Gas: 20.5 EUR/MWh, Coal: 31.8 EUR/t, CO_2: 59.7 EUR/t	▪ Interconnection Germany ▪ Biogas retrofit ▪ E-Methane green H2 retrofit
Sensitivity 1A KEV comm. prices	▪ Commodity price sensitivity using KEV 2030 ▪ 2030 prices: Gas: 23.2 EUR/MWh, Coal: 65.2 EUR/t, CO_2: 46.2 EUR/t	▪ Interconnection Germany ▪ Biogas retrofit ▪ E-Methane green H2 retrofit
Sensitivity 1B High CO2 price	▪ Commodity price sensitivity for CO_2 price ▪ 2030 CO_2 price: 100 EUR/t	▪ Interconnection Germany ▪ BECCS retrofit ▪ Wind offshore
Sensitivity 2A Less flex abroad	▪ Flex sensitivity abroad ▪ Capacity of thermal and battery flex reduced by 25% for Germany, UK and Belgium ▪ The scenario is quite extreme, with loss of load occurring in most countries	▪ Interconnection Germany ▪ Hydrogen blue H2 retrofit ▪ Biogas retrofit
Sensitivity 2B Less NTC	▪ Flex sensitivity abroad ▪ Interconnection capacity is reduced by 25% for Germany, UK and Belgium	▪ Interconnection Germany ▪ Biogas retrofit ▪ E-Methane green H2 retrofit
Sensitivity 3A Less domestic flex	▪ Flex sensitivity domestic ▪ Reduction of flexible demand within the Netherlands by 25%, for: Smart EVs, Smart heat pumps, Industrial DSR and Electrolysers	▪ Interconnection Germany ▪ Biogas retrofit ▪ E-Methane green H2 retrofit

Source: Aurora Energy Research

Reduced availability of flex capacities abroad with strongest impact on business case – less interconnection beneficial for many technologies

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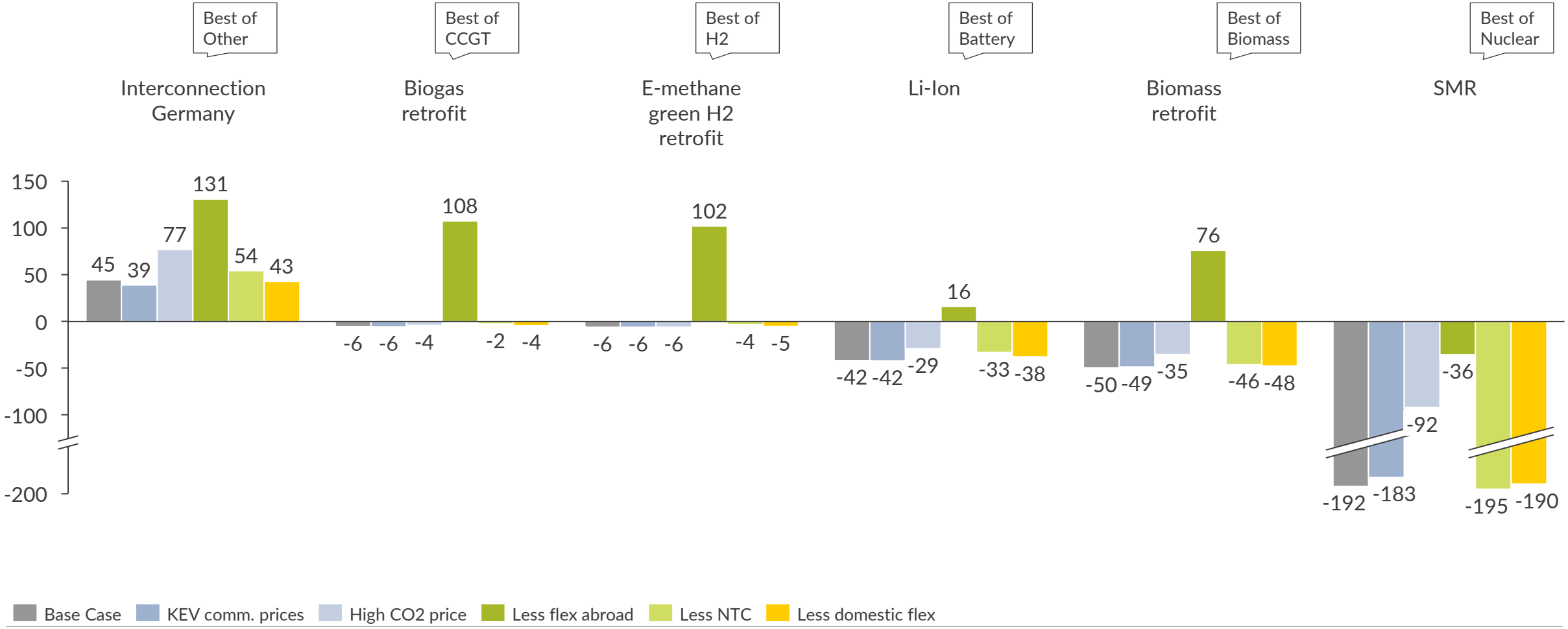
Gap to profitability 2030 – Best in class technologies
€/kW



Note: We assume a cost of capital (WACC) of 9%

Source: Aurora Energy Research

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In order to assess the economics of carbon-free flex technologies in the Dutch market post 2030, we performed a loss of load analysis

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In the following section(s), we will present analyses referring to Loss of Load. Assessing capacities in the power system vs. the demand is key to understanding the behaviour and economics of any production technology in the power market – checking whether and to which magnitude loss of load arises is an essential part of any such analysis. However, the **focus on this study is to assess the profitability of and need for carbon-free flexibility sources in the Dutch system** – our assessment gives a rough indication of required capacity, but conclusions on the exact magnitude of loss of load in a given year cannot be drawn

Scope of the study and treatment of loss of load

- Main goal of this study is to assess the profitability of and need for carbon-free flexibility sources in the Dutch system
- In order to size the capacities that need to be entered into the market from 2030 to 2050, we use as a first indicator the amount of loss of load that arises in this time period once thermal capacities are phased out
  - This analysis is repeated for a set of 10 Weather Years to take into account the variation that arises from different production patterns of wind and solar as well as different demand patterns (e.g. heat demand)
  - Yet, no statistical analysis is conducted of how often/ likely extreme hours do arise
- Taking this as a starting point, iterations were done to identify levels of capacity of carbon-free flex technologies that can operate economically

Outside of study scope

- There are studies, usually conducted by the TSOs, with the sole purpose of assessing security of supply and system adequacy of power markets, which usually include the below aspects to derive estimates of LOLE (Loss off Load Expectation)
  - Analysis of a broad set of weather years (30-40 years)
  - Statistical analysis to quantify the likelihood of certain extreme events arising again
  - Focus on the next 10-15 years, as uncertainties beyond that time increase strongly
- The depth of such an analysis goes beyond the scope of this study on carbon-free flexibility sources – results on loss of load arising in this study should thus only be interpreted in the context of the profitability of technologies

Source: Aurora Energy Research

We test ten different weather years – load factors lead RES generation to vary by up to ~20%, also demand fluctuates

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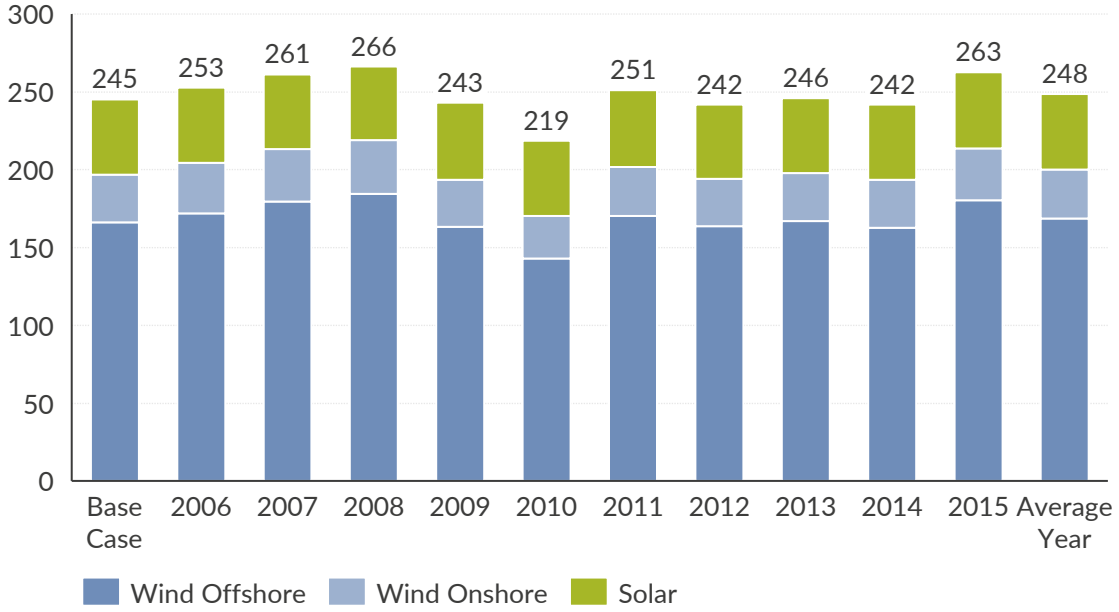
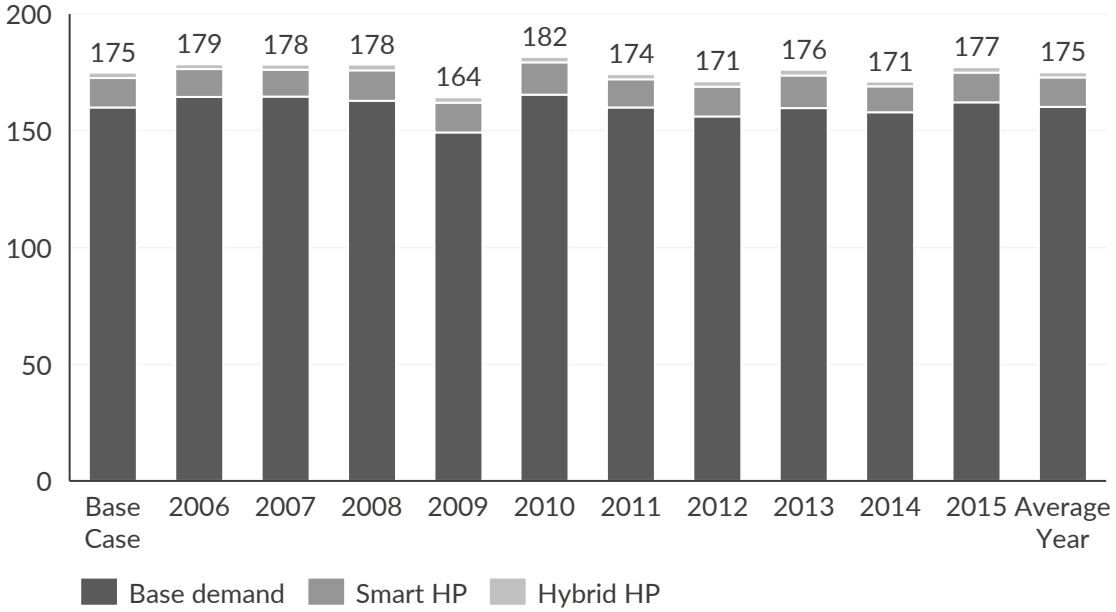
RES Generation – 2050
TWh



Comments

- Given offshore wind is the main RES-source, its fluctuations drive difference in RES generation – difference of >40 TWh between year of highest production (WY 2008) and year of lowest production (WY 2010)
  - Up to ~47 TWh total difference in RES generation between these years

Base demand and heat pump demand – 2050
TWh



Comments

- The weather years have also different inputs on the demand side
  - Base demand is the main driver here, up to ~16 TWh difference between WY 2009 and WY 2010
  - Also heat pump demand differs – up to ~2.5 TWh of additional variation between weather years

Note: WY = Weather Year

Source: Aurora Energy Research

As a response to different model inputs for RES generation and demand, flexible production and demand technologies adjust

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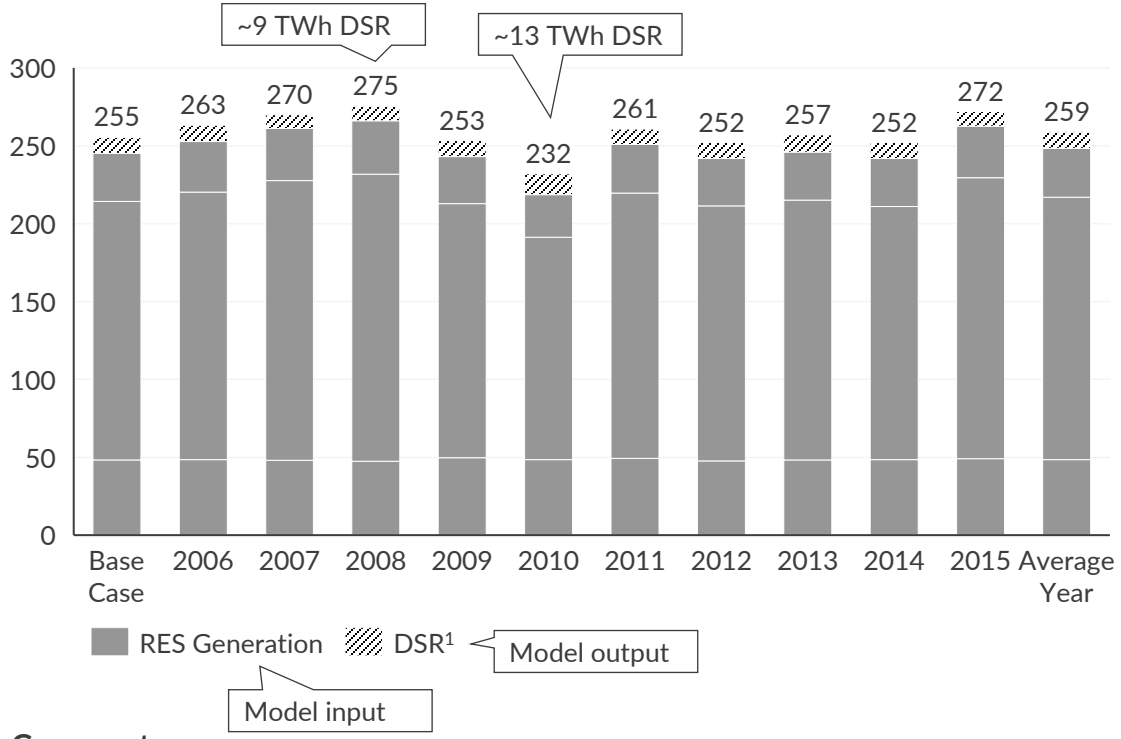
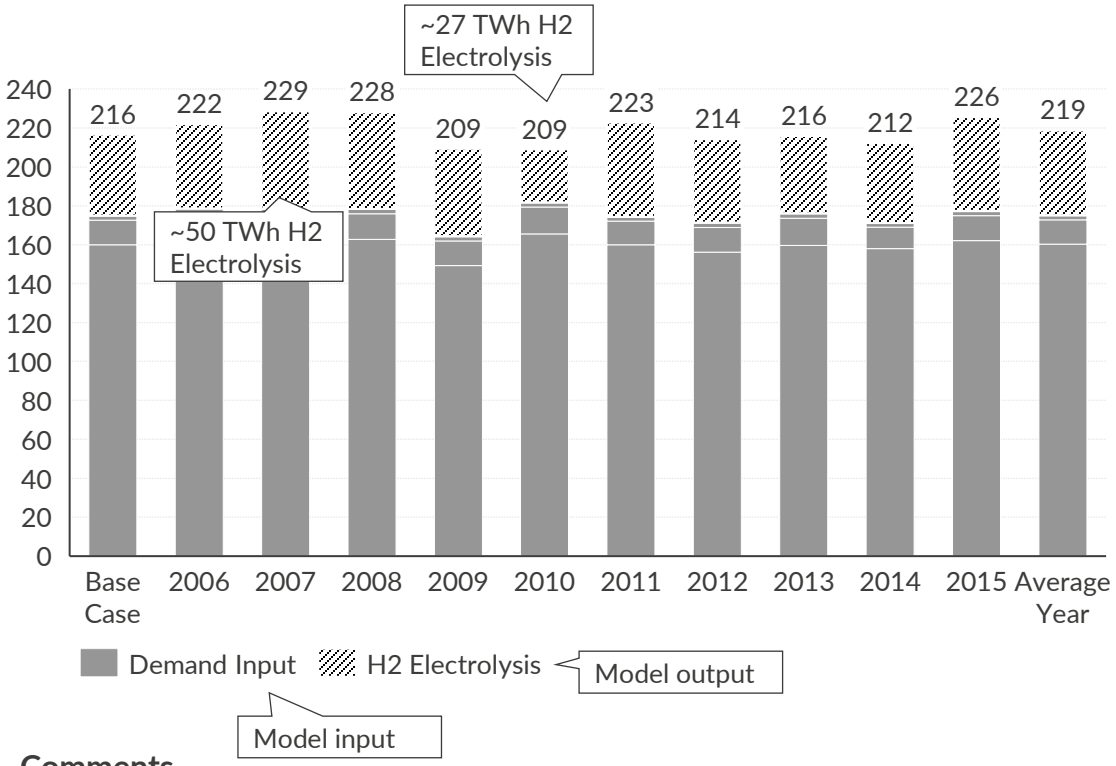
RES Generation – 2050
TWh



Comments

- Given the different RES generation and demand between weather years, demand side response adjusts generation, >4 TWh difference between WY

Demand from flexible sources – 2050
TWh



Comments

- H2 electrolysis will adjust to different RES production and demand patterns, up to 23 TWh in difference between weather years

Note: WY = Weather Year; 1) Demand Side Response

Source: Aurora Energy Research

In 2040, depending on weather year, up to ~800 hours of loss of load, ~2 TWh of unmet demand and ~14 GW max loss of load

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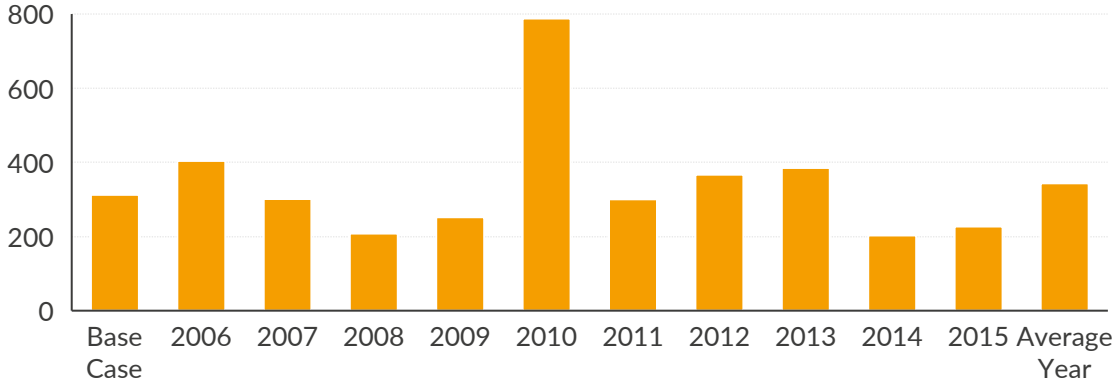
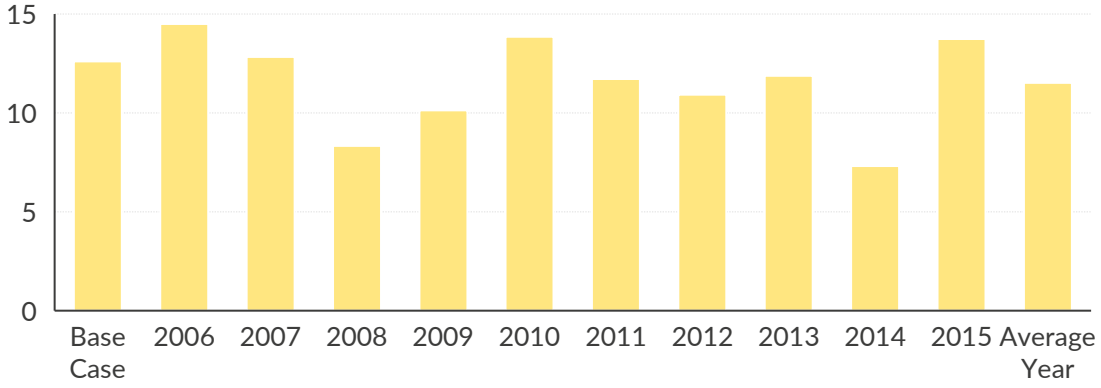
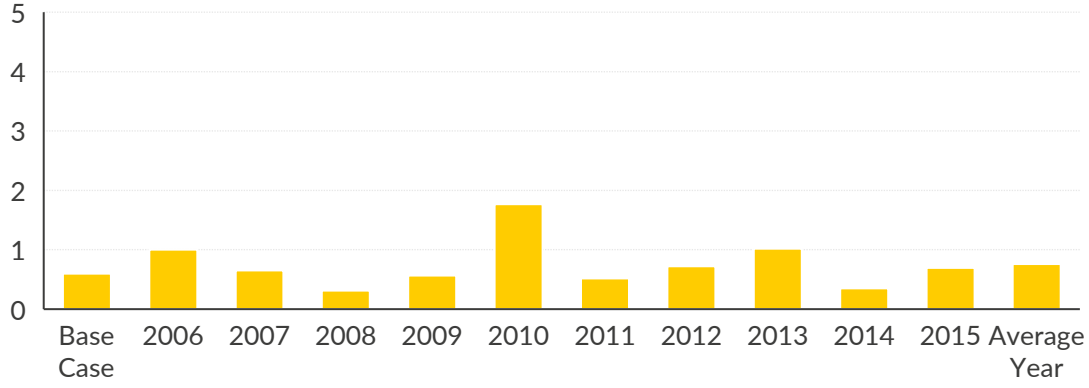
Loss of load numbers of hours – 2040
h



Maximum loss of load – 2040
GW



Loss of load depth – 2040
TWh



Comments

- WY 2010 is most extreme weather year
  - Leads to ~800 hours where loss of load occurs as well as nearly 2 TWh of unmet demand by 2050
  - Not the highest WY in terms of maximum loss of load
- WY 2006 leads to highest maximum loss of load in 2050, amounting to ~14 GW of loss of load in the most extreme hour
- WY 2008 and WY 2014 with very little loss of load over all categories

Note: This section covers loss of load when only considering RES and the remaining thermal assets - without having added the flex production technologies.

Source: Aurora Energy Research

In 2050, depending on weather year, up to ~2,000 hours of loss of load, ~8 TWh of unmet demand and ~23 GW max loss of load

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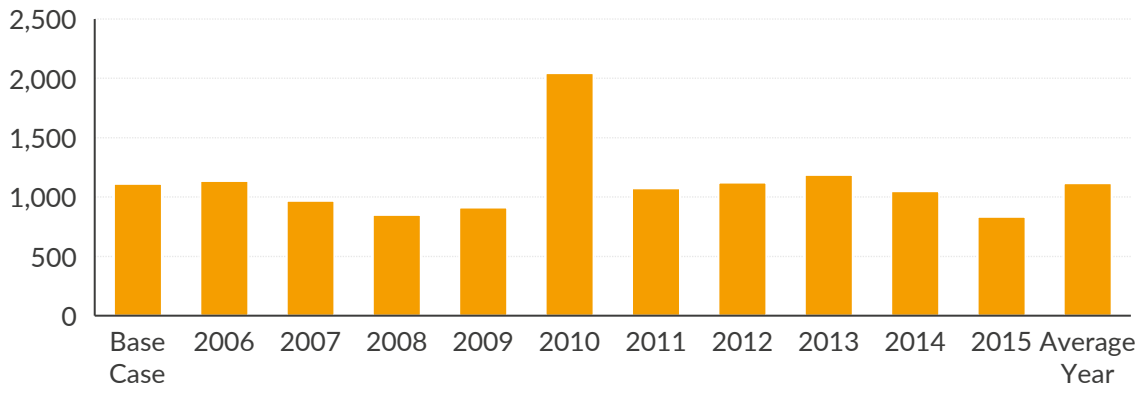
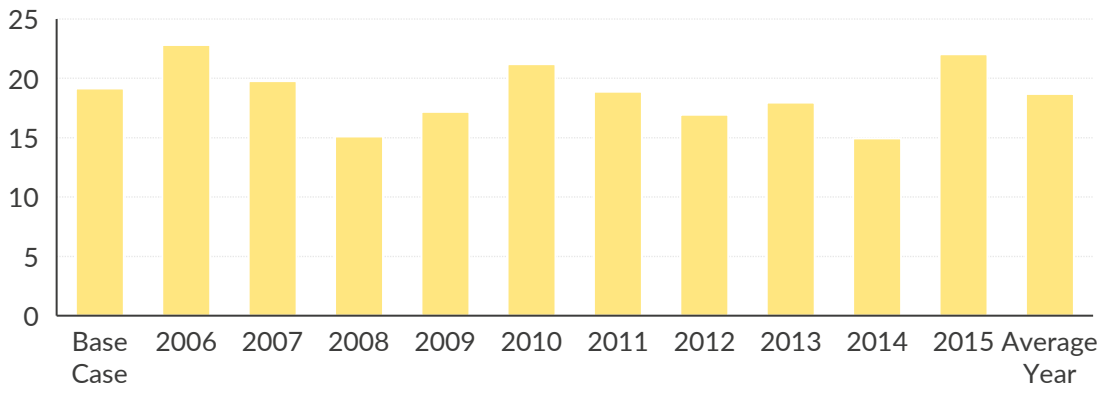
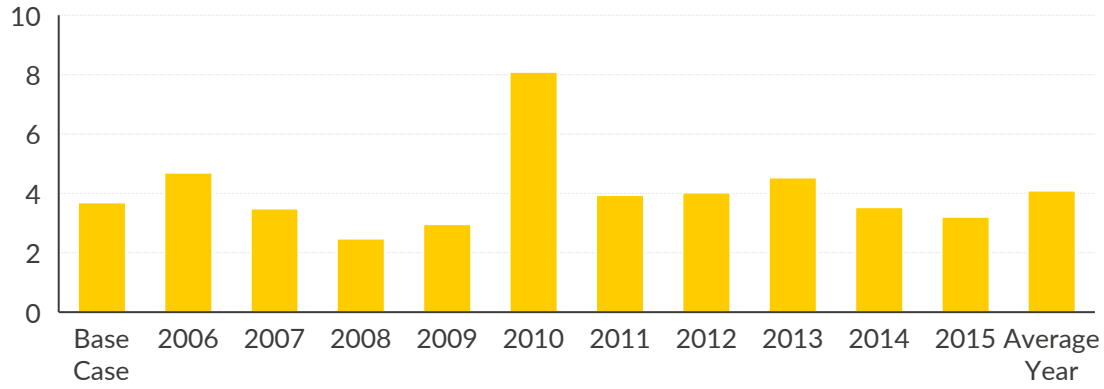
Loss of load numbers of hours – 2050
h



Maximum loss of load – 2050
GW



Loss of load depth – 2050
TWh



Comments

- WY 2010 is most extreme weather year
  - Leads to ~2000 hours where loss of load occurs as well as ~8 TWh of unmet demand by 2050
  - Not the highest WY in terms of maximum loss of load
- WY 2006 leads to highest maximum loss of load in 2050, amounting to ~23 GW of loss of load in the most extreme hour
- WY 2008 with very little loss of load over all categories

Note: This section covers loss of load when only considering RES and the remaining thermal assets - without having added the flex production technologies.

Source: Aurora Energy Research

Average weather year with ~4 TWh of unmet demand by 2050 – wide range from 2.5 TWh to 8 TWh

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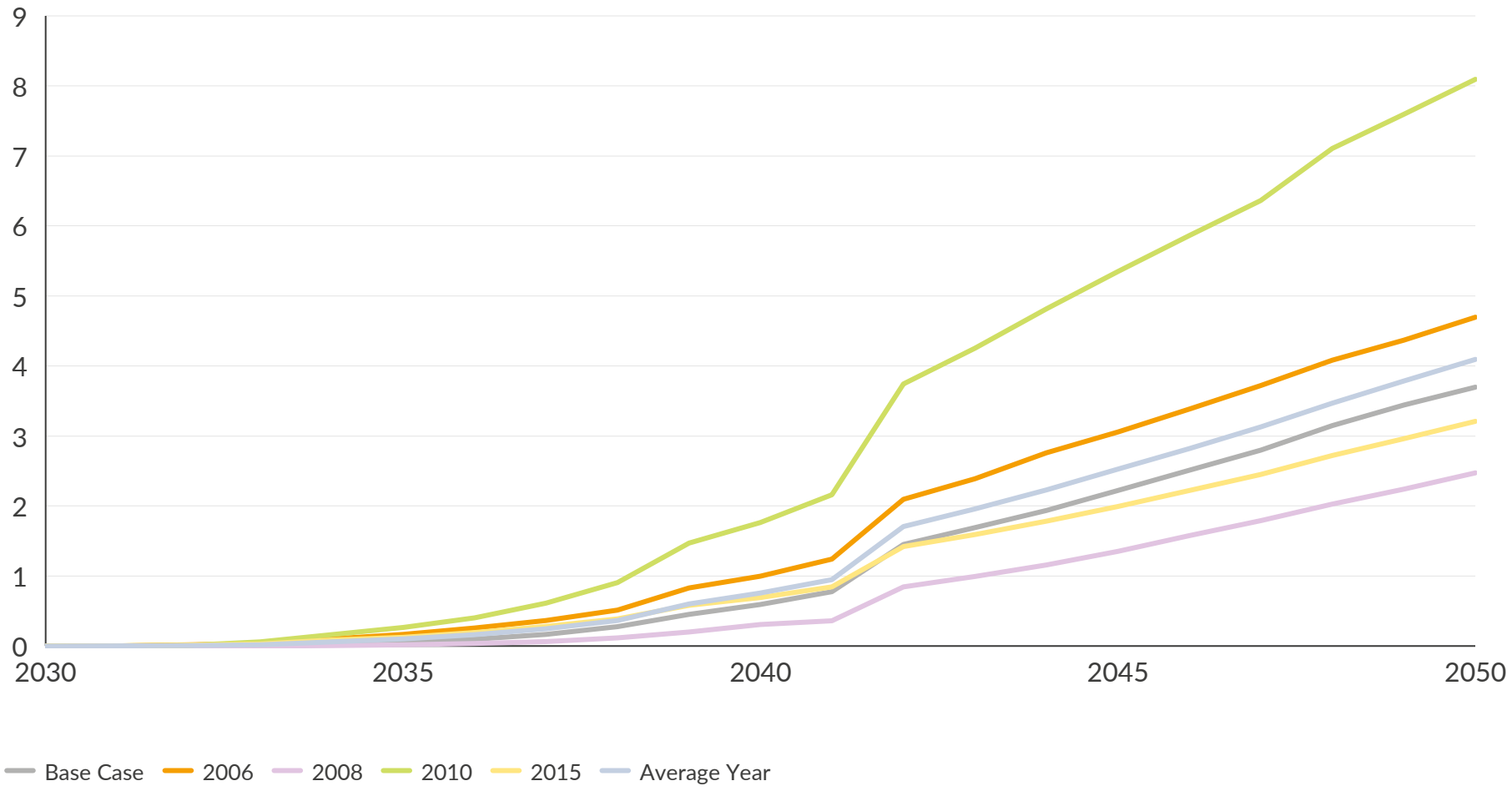
Loss of load depth
TWh



Note: This section covers loss of load when only considering RES and the remaining thermal assets - without having added the flex production technologies.

Source: Aurora Energy Research

Comments

- Outside of the base case and the average year, we only present select weather years to keep visibility high:
  - WY 2006: Highest max loss of load
  - WY 2008: least problems with loss of load
  - WY 2010: highest number of loss of load hours and depth of loss of load
  - WY 2015: High peak loss, but limited number of hours and max loss of load

Strong increase of the numbers of hours with loss of load over time – most scenarios with 800 – 1,200 hours by 2050

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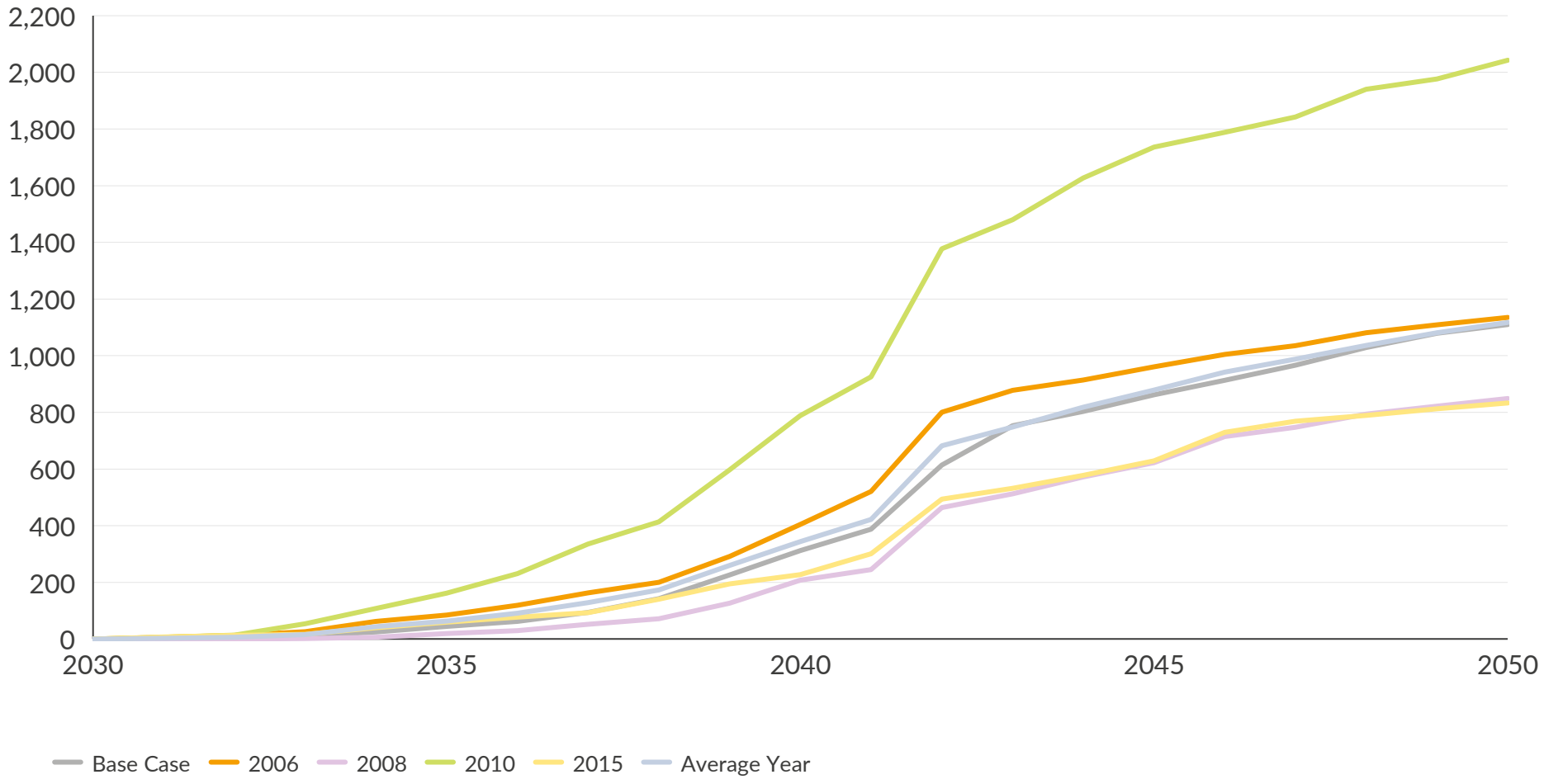
Loss of load numbers of hours

h



Note: This section covers loss of load when only considering RES and the remaining thermal assets - without having added the flex production technologies.

Source: Aurora Energy Research

Comments

- Outside of the base case and the average year, we only present select weather years to keep visibility high:
  - WY 2006: Highest max loss of load
  - WY 2008: least problems with loss of load
  - WY 2010: highest number of loss of load hours and depth of loss of load
  - WY 2015: High peak loss, but limited number of hours and max loss of load

Several years with loss of load of >20 GW by 2020 – even least drastic WY 2008 with >15 GW in most extreme hour

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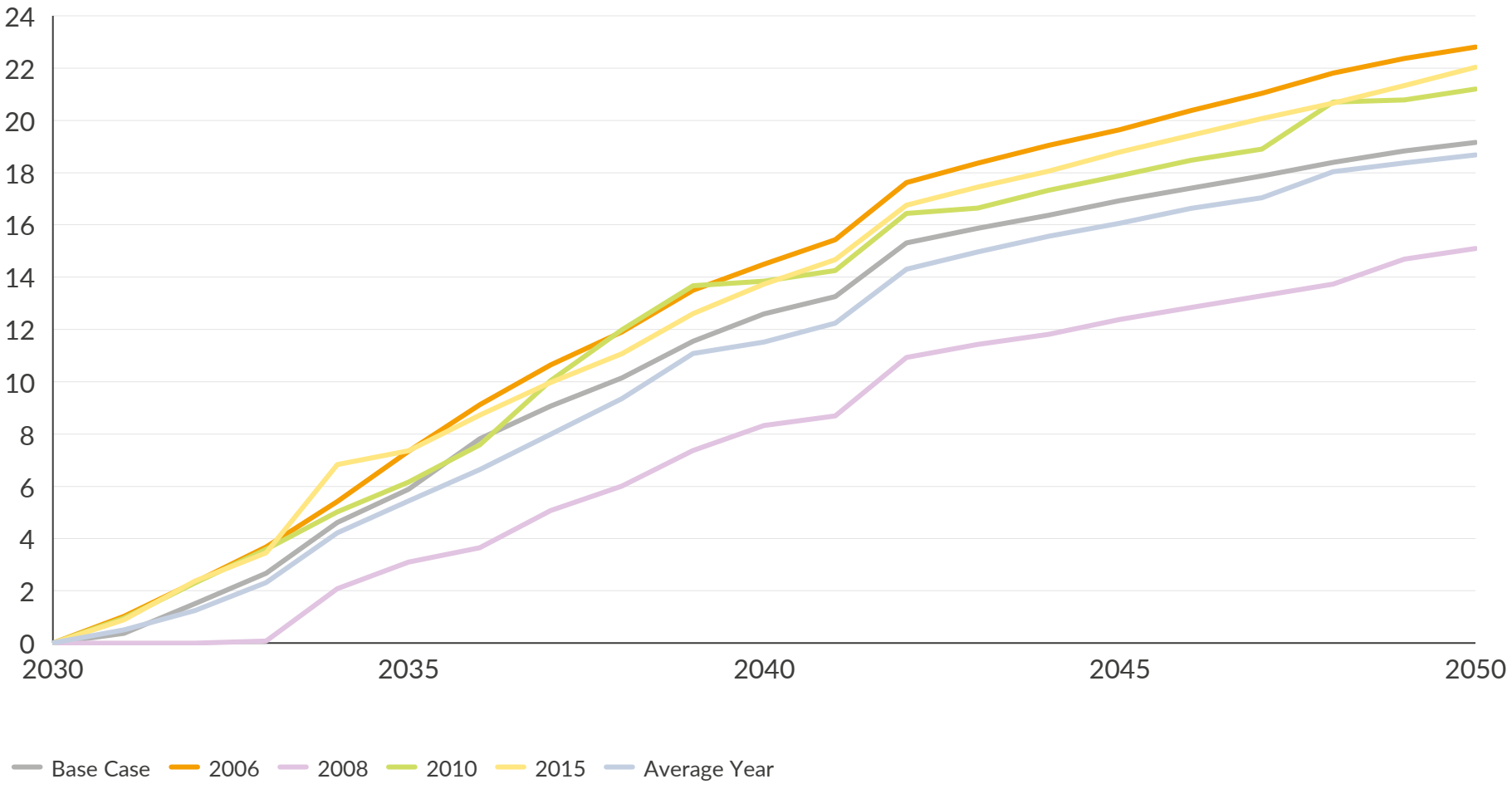
Maximum Loss of Load
GW



Note: This section covers loss of load when only considering RES and the remaining thermal assets - without having added the flex production technologies.

Source: Aurora Energy Research

Comments

- Outside of the base case and the average year, we only present select weather years to keep visibility high:
  - WY 2006: Highest max loss of load
  - WY 2008: least problems with loss of load
  - WY 2010: highest number of loss of load hours and depth of loss of load
  - WY 2015: High peak loss, but limited number of hours and max loss of load

While hours of extreme loss of load already occur in 2040, their number increases strongly within the ten years up to 2050

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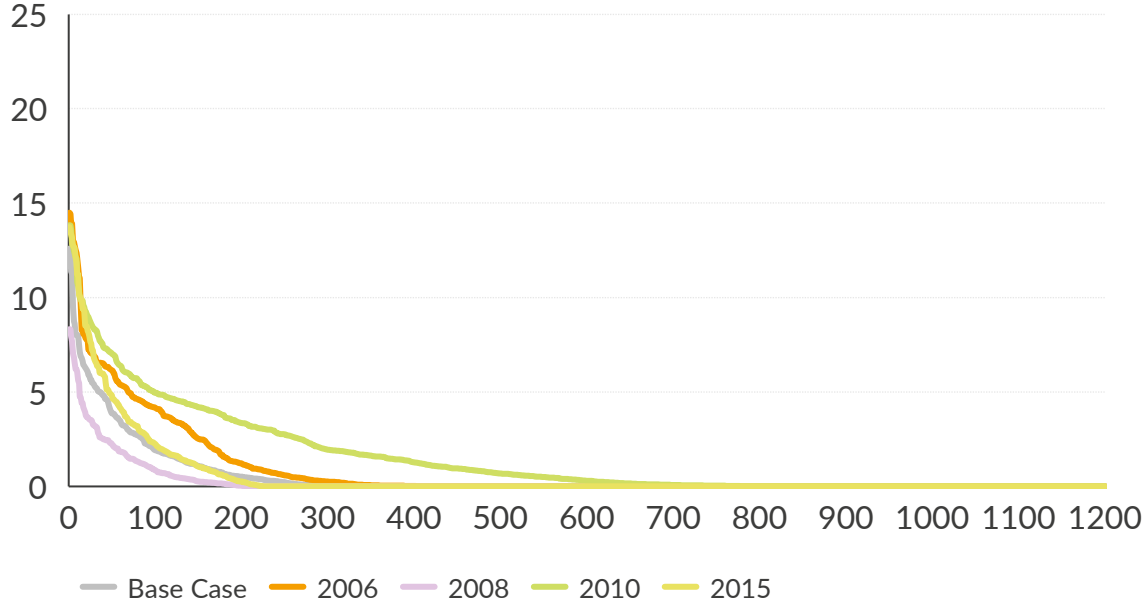
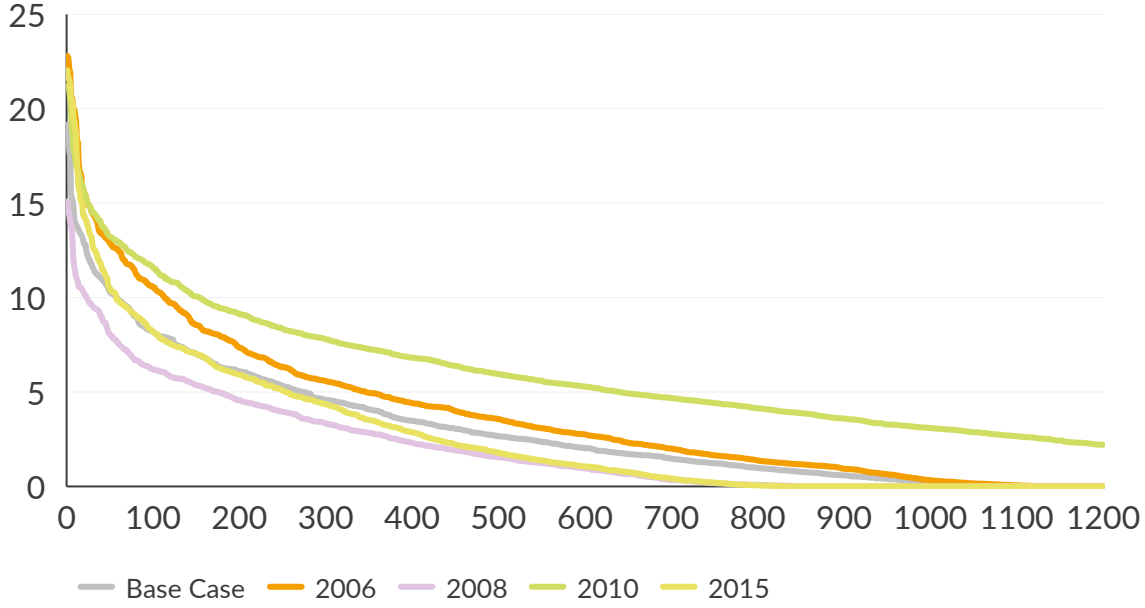
Loss of load duration curve top 1200 hours – 2040
GW (sorted)



Loss of load duration curve top 1200 hours – 2050
GW (sorted)



Comments

- In 2040, for most weather years only a small amount of hours exhibit high loss of load – usually less than 300 hours
- WY 2010 again is the exception, where more than twice that many hours show significant loss of load

Comments

- By 2050, the picture has changed – in all weather years there are many hours with high loss of load
- Still, between WY 2008 (least hours) and WY 2010 (most hours) the difference is stark – e.g. three times as many hours with 5 GW loss of load

Note: This section covers loss of load when only considering RES and the remaining thermal assets - without having added the flex production technologies.

Source: Aurora Energy Research

Share of hours >100 EUR/MWh and <20 EUR/MWh increases by factor 3 from 2030 to 2050 in base case – very high volatility

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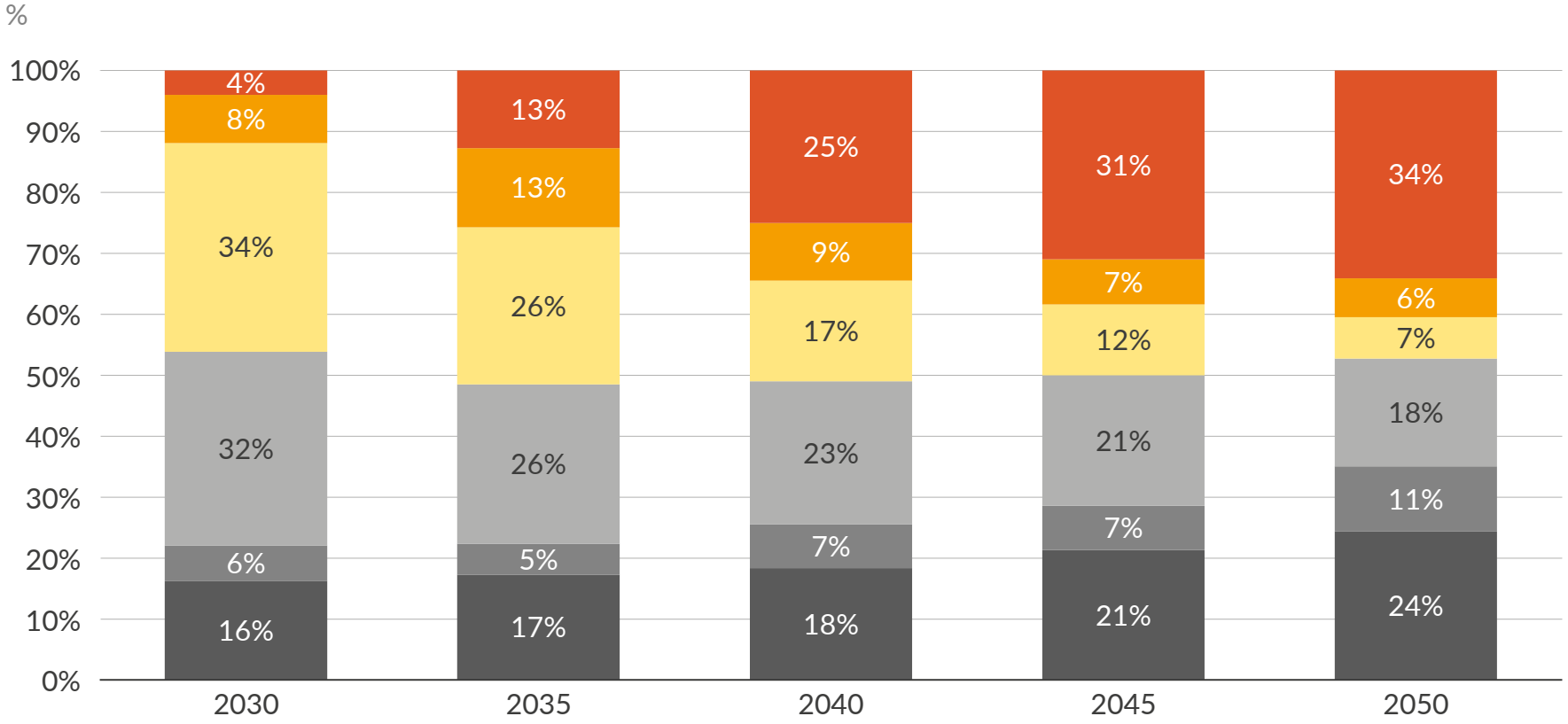
Frequency distribution of the electricity price



Standard deviation

2030	2035	2040	2045	2050
86	305	626	972	1,091

<€20 €20-40 €40-60 €60-80 €80-100 >€100

Note: Numbers from aligned project base case

Source: Aurora Energy Research

Comments

- Wholesale prices are expected to become increasingly volatile, as gas is phased out and the buildout of renewables progresses fast
- The frequency of high prices (>100 EUR/MWh) increases by 30 p.p. between 2030 and 2050, as loss of load situations become more frequent where prices skyrocket
- The frequency of low prices (<20 €/MWh) increases by 8 p.p. between 2030 and 2050 as renewables set prices more frequently
- The increasing frequency of high and low prices translates to an increase in price volatility, as evidenced by the increase in standard deviation over time

Without thermal capacities, prevalence of loss of load situations leads to wholesale price of >500 EUR/MWh by 2050 in base case

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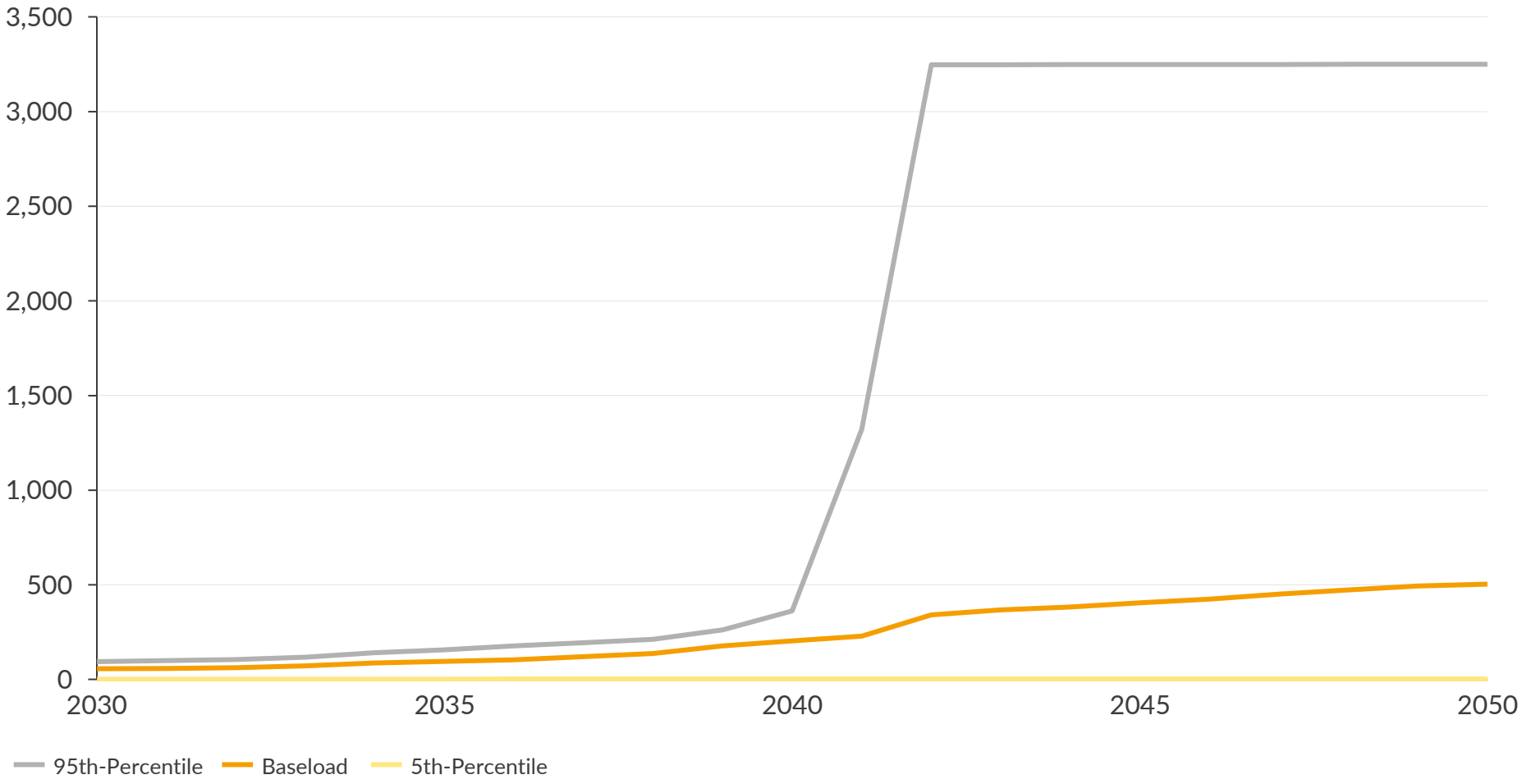
Wholesale price and percentiles
EUR/MWh



Note: This section covers loss of load when only considering RES and the remaining thermal assets - without having added the flex production technologies.

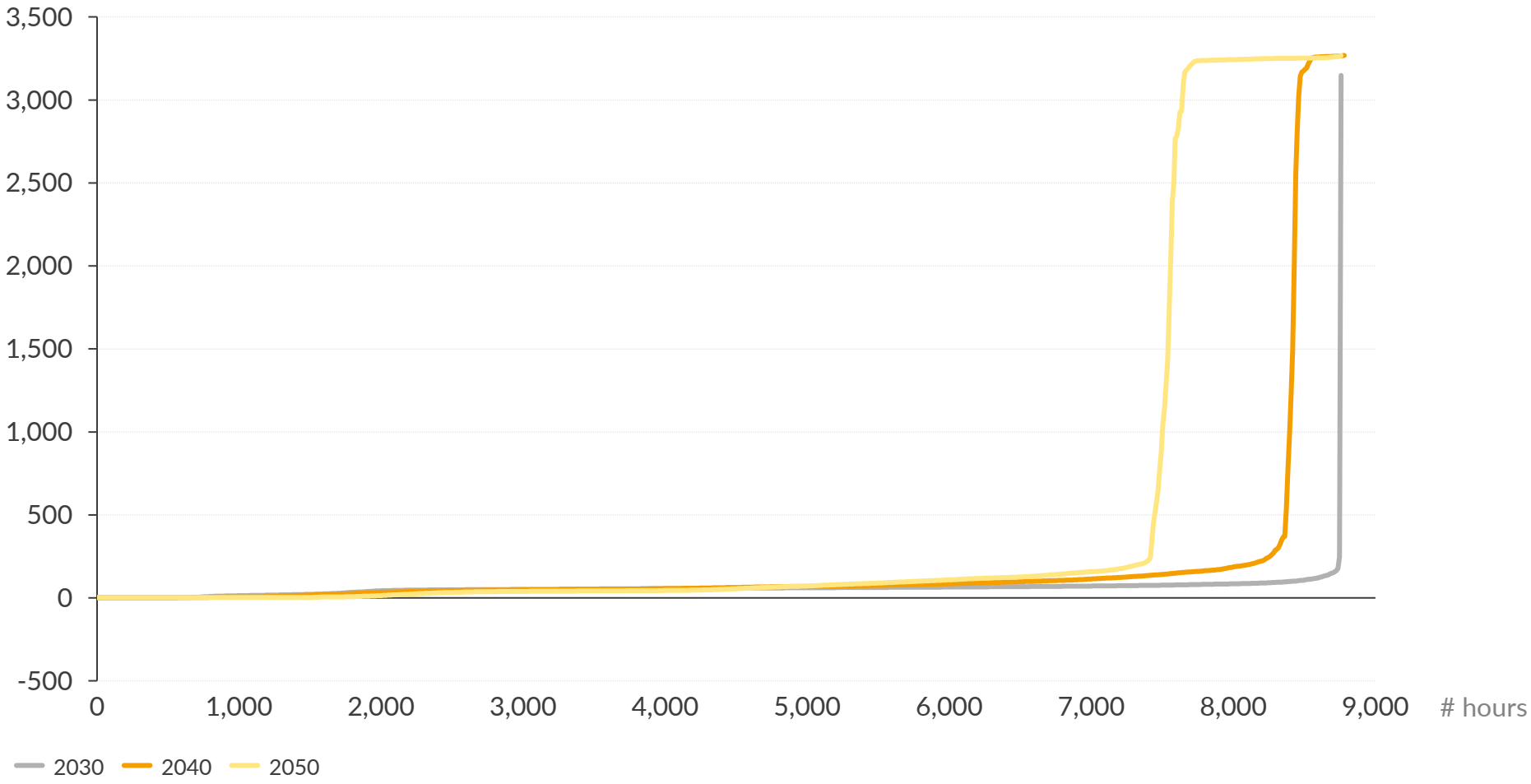
Source: Aurora Energy Research

Comments

- Average wholesale price rises from ~60 EUR/MWh in 2030 to ~200 EUR/MWh by 2040 and ~500 EUR/MWh by 2050
  - This is because there are plenty of situations where loss of load occurs and prices skyrocket to >3k EUR/MWh
- The most expensive prices (95th -percentile) rise from ~400 EUR/MWh in 2040 to ~3,330 EUR in 2050, driving up the average wholesale price
- On the other hand, the movement of cheap prices is very limited – the 5th-percentile moves from ~1 EUR/MWh to ~2 EUR/MWh over the 20 year horizon

Price distribution curve (1/2): Number of extreme price hours (>1k EUR/MWh) increases strongly to over ~1,000 hours in 2050

Price distribution curve
EUR/MWh



Note: This section covers loss of load when only considering RES and the remaining thermal assets - without having added the flex production technologies.

Source. Aurora Energy Research

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Comments

- In 2030, there are very few hours with extreme prices
  - Only very few hours with prices over 1k EUR/MWh
  - In ~700 hours, prices are below 5 EUR/MWh
- In 2040, more hours with extreme prices emerge – both on the high and on the low end
- By 2050, many hours in the year are characterized by extreme prices
  - In over 1,000 hours, prices top 1k EUR/MWh
  - In >1,500 hours, prices stay below 5 EUR/MWh

Price distribution curve (2/2): With more RES-generation, also the number of extremely low-priced hours increases towards 2050

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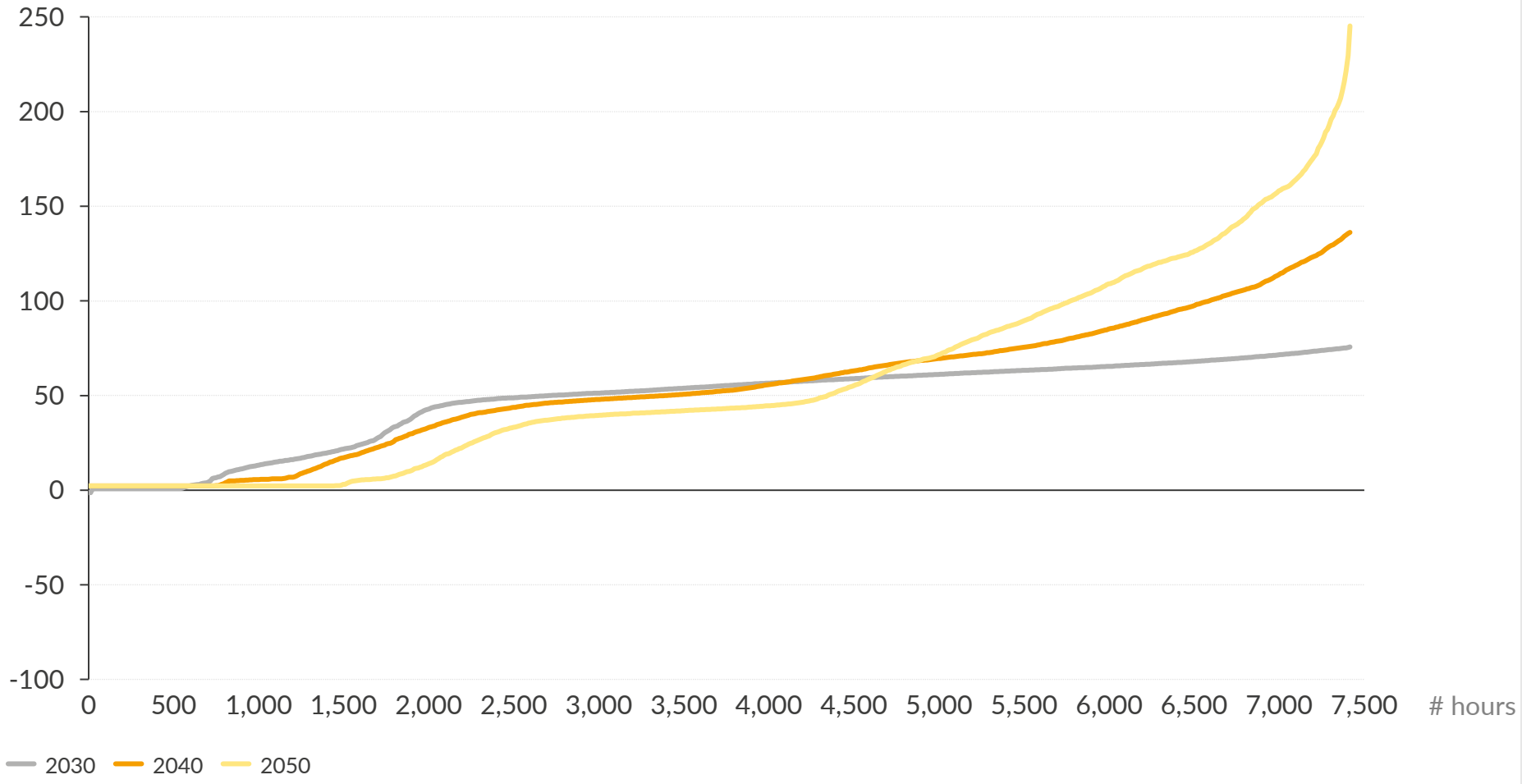
Price distribution curve
EUR/MWh

Zoom-in from previous slide to make differences in lower-priced hours visible



Note: This section covers loss of load when only considering RES and the remaining thermal assets - without having added the flex production technologies.

Source. Aurora Energy Research

Comments

- In 2030, there are very few hours with extreme prices
  - Only very few hours with prices over 1k EUR/MWh
  - In ~700 hours, prices are below 5 EUR/MWh
- In 2040, more hours with extreme prices emerge – both on the high and on the low end
- By 2050, many hours in the year are characterized by extreme prices
  - In over 1,000 hours, prices top 1k EUR/MWh
  - In >1,500 hours, prices stay below 5 EUR/MWh

Flexible demand technologies take advantage of the high production and volatile patterns of renewable power sources in summer

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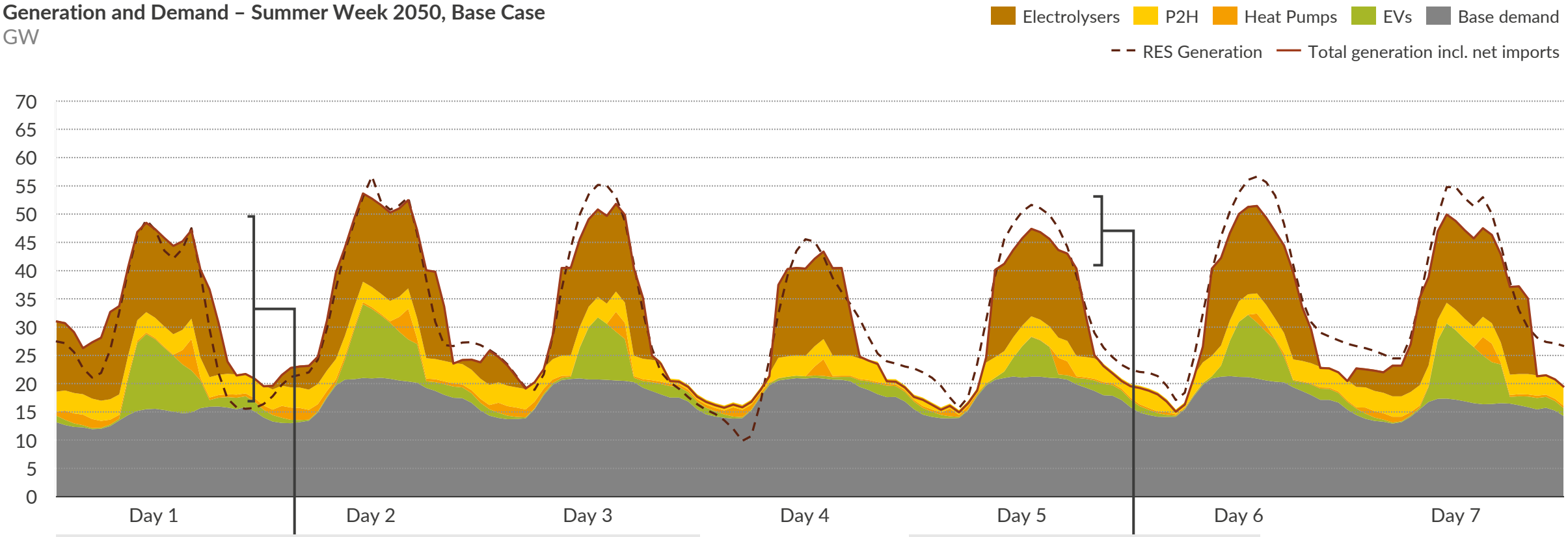
Generation and Demand – Summer Week 2050, Base Case
GW



EVs, Heat pumps, P2H (E-Boilers) and Hydrogen-Electrolysers provide an enormous amount of flexible demand, allowing effective use of renewables' generation curves.
In winter months, heat pump demand flexibility plays a much more significant role.

When there is not enough demand to consume all the RES generation domestically, surplus power gets exported to neighbouring countries.

Note: Numbers from aligned project base case

Source: Aurora Energy Research

During winter, RES generation and imports will not always be enough to cover demand – loss of load occurs frequently

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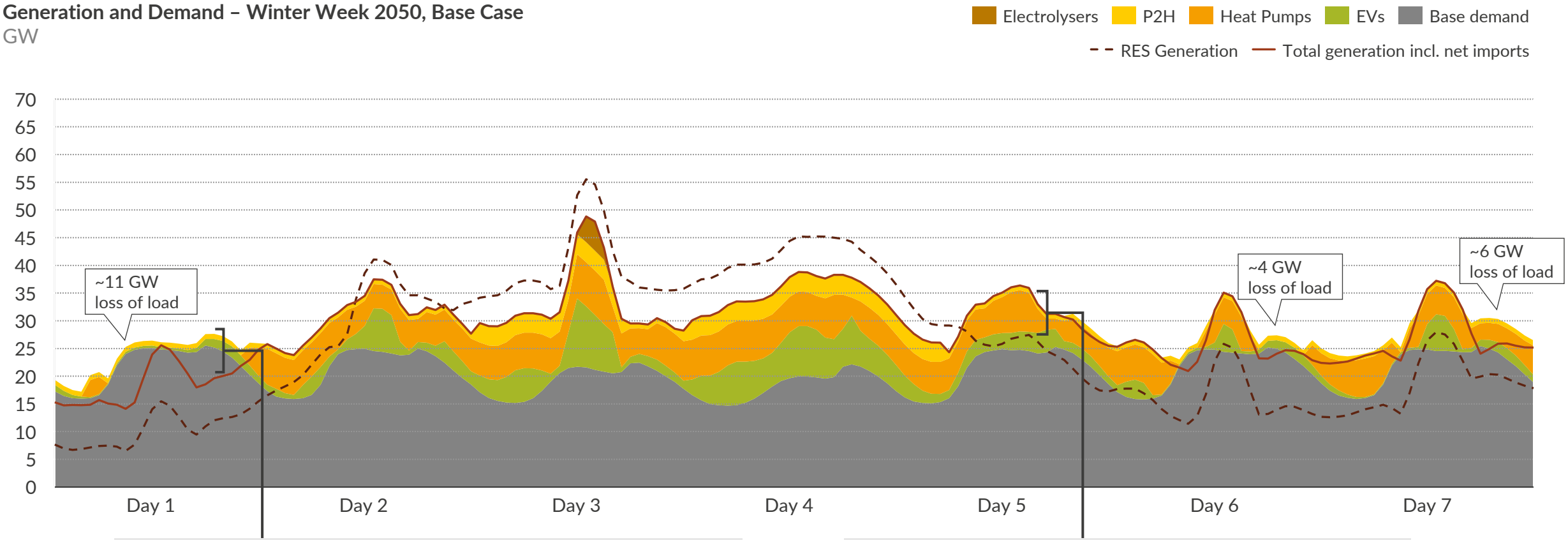
Generation and Demand – Winter Week 2050, Base Case
GW



Even with imports, the generation from wind and solar alone will not be sufficient to cover demand.
This is where loss of load occurs in our base case. In this instance, ~9 GW of loss of load occur during a Monday evening.

In winter, heat pumps can provide an increased amount of flexibility during hours of high RES production.
They will also shift (smart electric heat pumps) or adjust (hybrid heat pumps) to avoid / reduce loss of load.

Note: Numbers from aligned project base case

Source: Aurora Energy Research

Agenda

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Without additional flex capacity, loss of load would reach unacceptable levels; to solve this a mix of long-, short-duration and back-up capacity is required

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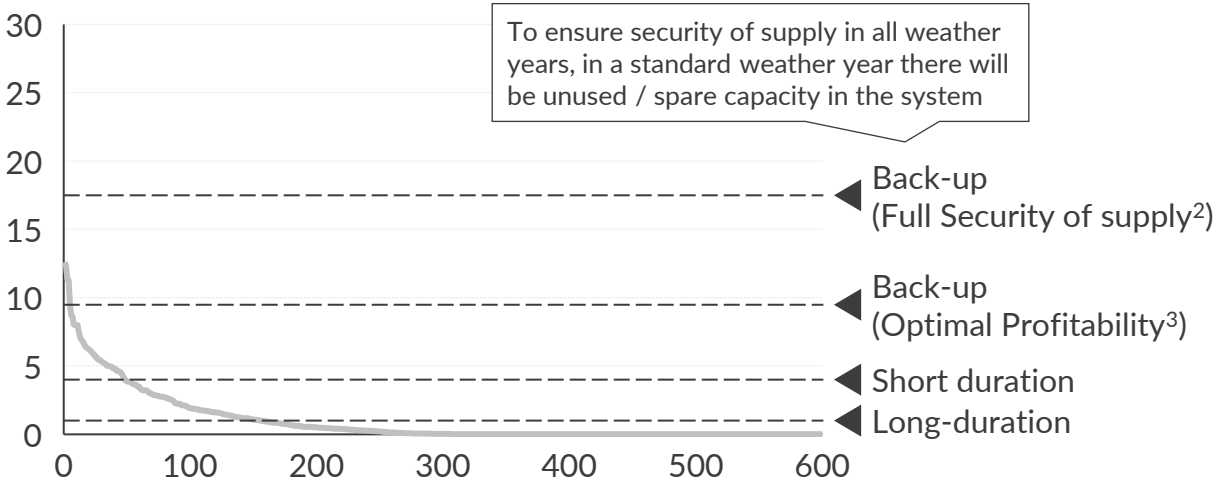
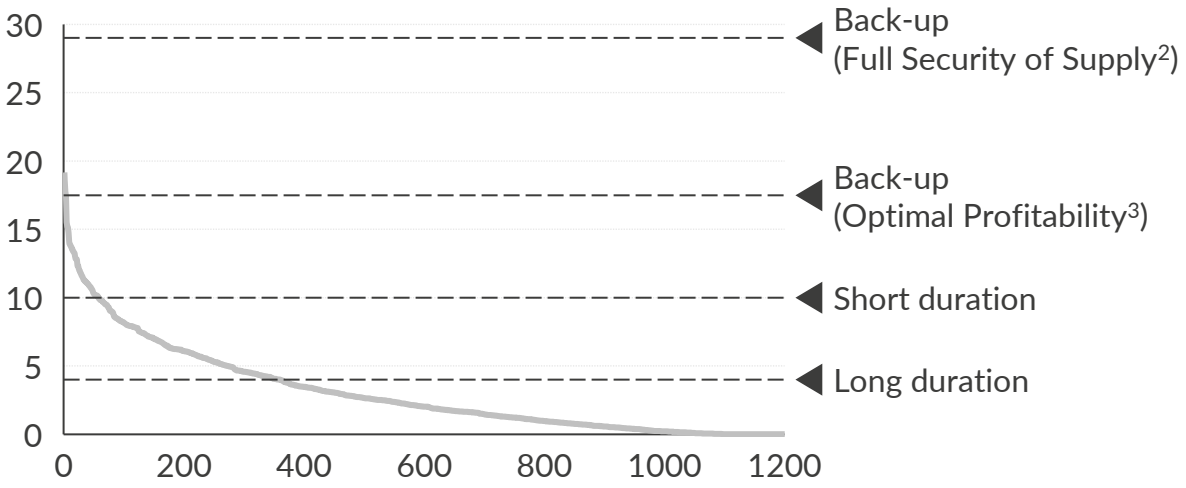
Loss of load duration curve for top 600 hours – 2040, Standard WY[1]
GW (sorted)



Loss of load duration curve for top 1200 hours – 2050, Standard WY[1]
GW (sorted)



Comments

- In 2040 there is only few capacity needed that has to run many hours – most extra capacity to prevent loss of load needs to run less than 100 hours
- The peak in loss of load in our standard weather year is ~13 GW, but in the most extreme scenario this was 14.5 GW

Comments

- In 2050, close to 4 GW of capacity is needed to run >400 hours, but capacity need is still dominated by back-up
- The peak in loss of load in our standard weather year is ~19 GW, but in the most extreme scenario this was 23 GW

Flex capacities were dimensioned in an iterative way: based on the loss of load duration curves, initial estimates of appropriate capacities for the different types of flexible capacities were formed. Then we iterated in order to achieve the goals of the respective scenarios: ensuring Full Security of Supply (e.g. also in extreme weather years), or enhancing asset profitability while keeping loss of load at a minimum. We also considered the reduced availability of batteries in situations of peak demand and dropping RES generation.

1) WY = Weather Year; 2) Ensures no loss of load occurs – details on following slides; 3) Enhances profitability of technologies – details on following slides

Source: Aurora Energy Research

Three different technology mixes were developed – they mainly differ by the technology that is used to offer long-duration flex

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	Technology Mix 1	Technology Mix 2	Technology Mix 3
Technologies	▪ Long duration flex: – Hydrogen CCGTs ▪ Short-duration flex: – Lithium-Ion Batteries ▪ Back-up flex: – Hydrogen OCGTs	▪ Long duration flex: – Nuclear SMRs[1] ▪ Short-duration flex: – Lithium-Ion Batteries ▪ Back-up flex: – E-Methane OCGTs	▪ Long duration flex: – BECCS – Gas CCS ▪ Short-duration flex: – Lithium-Ion Batteries ▪ Back-up flex: – Hydrogen OCGTs
Rationale	▪ Hydrogen CCGTs are one effective option to offer long-duration flexibility in a high-RES system – They have a high efficiency and can still respond flexibly to power prices (compared to nuclear, BECCS) – Price of hydrogen will decline over time and increase their competitiveness – At least partly, existing assets can be used by retrofitting ▪ Lithium-Ion batteries can provide flexibility within the day and help balance short-term fluctuations in RES production and demand ▪ In the most extreme hours, only back-up will be able to ensure security of supply – hydrogen OCGTs as one carbon-free option	▪ Nuclear SMRs are an alternative to ensure security of supply that differs from hydrogen CCGTs – While nuclear power plants cannot offer flexibility per se, having them operate as baseload in a high-RES power system allows demand flex technologies and batteries to take advantage of shifting supply and demand – Nuclear SMRs will still run >7k hours and be in the merit order right behind RES ▪ For OCGTs, e-methane can be used as an alternative fuel – Due to efficiency losses the fuel is more expensive than H2. However, already existing infrastructure can be used	▪ BECCS can play an important role as one pillar to ensure the security of supply – Like nuclear SMRs, BECCS plants do not offer flexibility by themselves but rather do that by being combined with batteries and flexible demand – Rising carbon prices make it a highly profitable option, additionally existing coal plants can be retrofitted ▪ Gas CCS represents an effective supplement for BECCS, which is limited by the availability of biomass – CCGTs ramp more flexibly than the coal plants, offer high efficiency and low marginal costs – even considering the additional cost for carbon capture

1) SMR = Small Modular Reactor

Source: Aurora Energy Research

Tech Mix 1 uses H2 CCGTs for long-duration, Tech Mix 2 Nuclear SMRs and Tech Mix 3 a combination of retrofitted BECCS and Gas CCS

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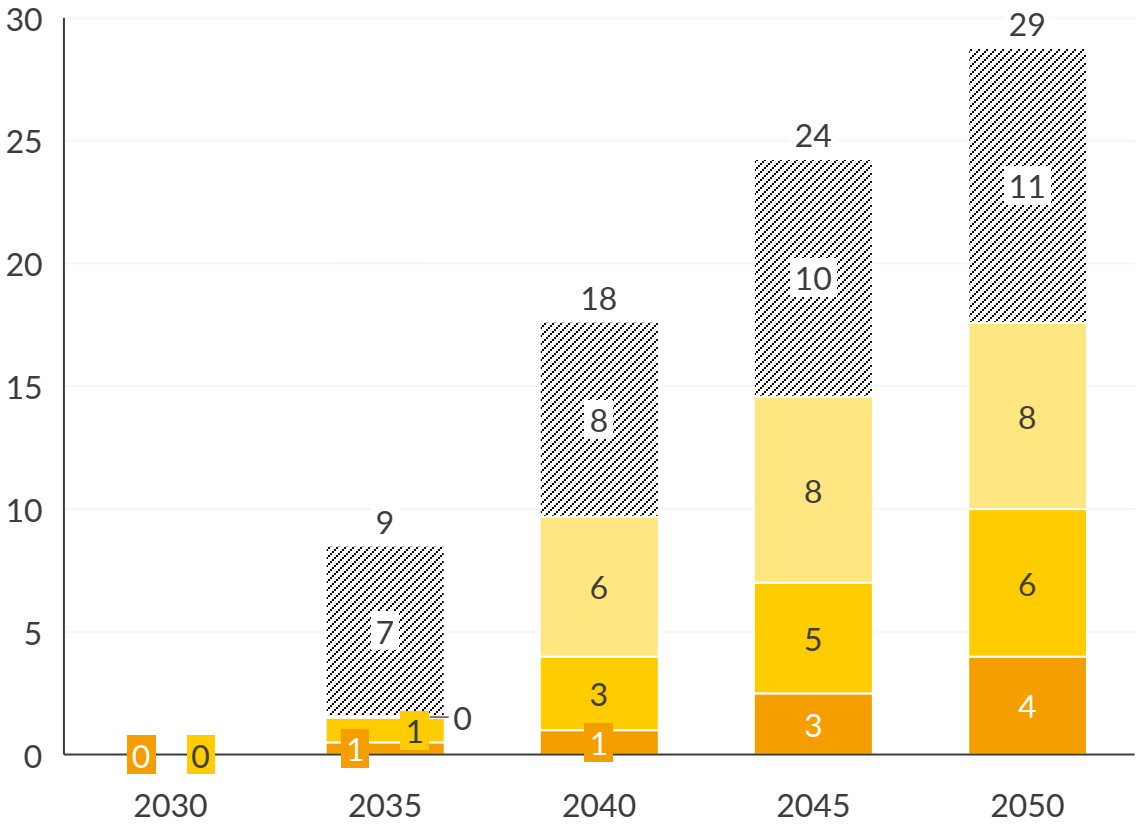
CO_2 free flexible capacities
GW



Long duration flex | Short duration flex | Back-up - Opt. profitability | Back-up - Full sec. of supply

Technologies	Tech Mix 1	Tech Mix 2	Tech Mix 3
Long duration flex	H2 CCGT	Nuclear SMR	BECCS/Gas CCS
Short duration flex	Li-Ion	Li-Ion	Li-Ion
Back-up flex	H2 OCGT	E-methane OCGT	H2 OCGT

Comments

- In both scenarios, long and short duration flex are being built out up to 4 GW and 6 GW in 2050, respectively
- In Tech Mix 3, the long duration flex capacity in 2050 consists of
  - 1 GW of BECCS (retrofit)
  - 3 GW of Gas CCS
- The only difference between the optimal profitability and the full security of supply scenario lies in the back-up capacity:
  - A much scarcer system is being created in the optimal profitability scenario by reducing the back-up capacity from ~19 GW to ~8 GW

Note: The above graphs shows the capacities that were added to the base case in the course of creating the technology mixes. All scenarios still have nuclear power plant Borssele operating until 2033.

Source: Aurora Energy Research

For technologies to operate profitably, the market needs to be tight – up to 10 hours of loss of load and a maximum of 7 GW peak LoL

No LoL in Full Sec. of Supply Scenario

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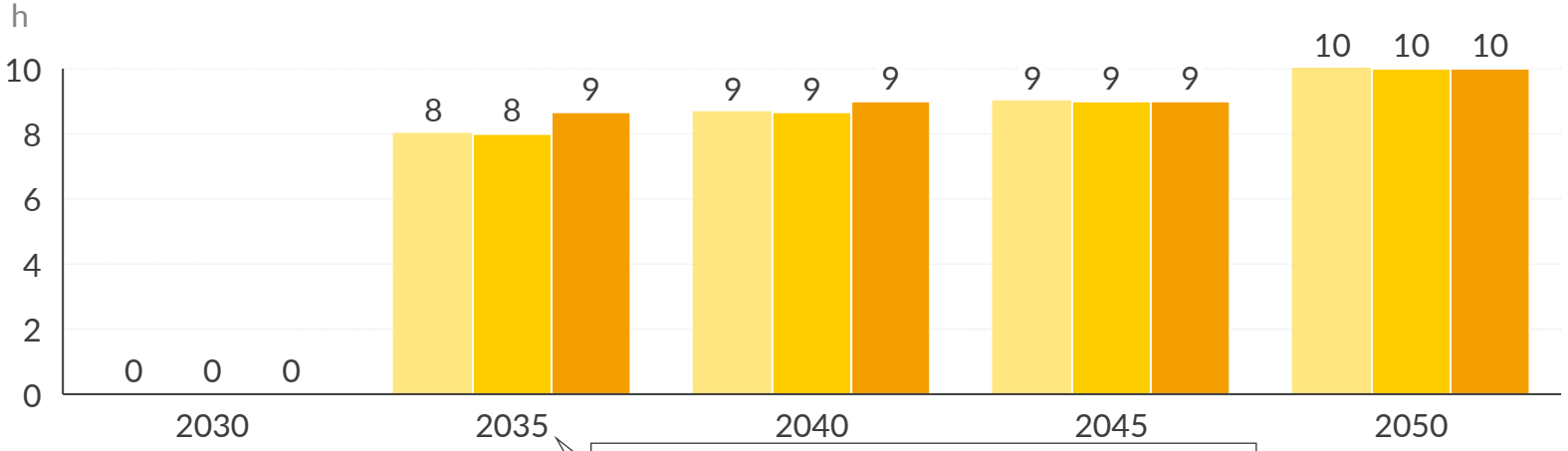
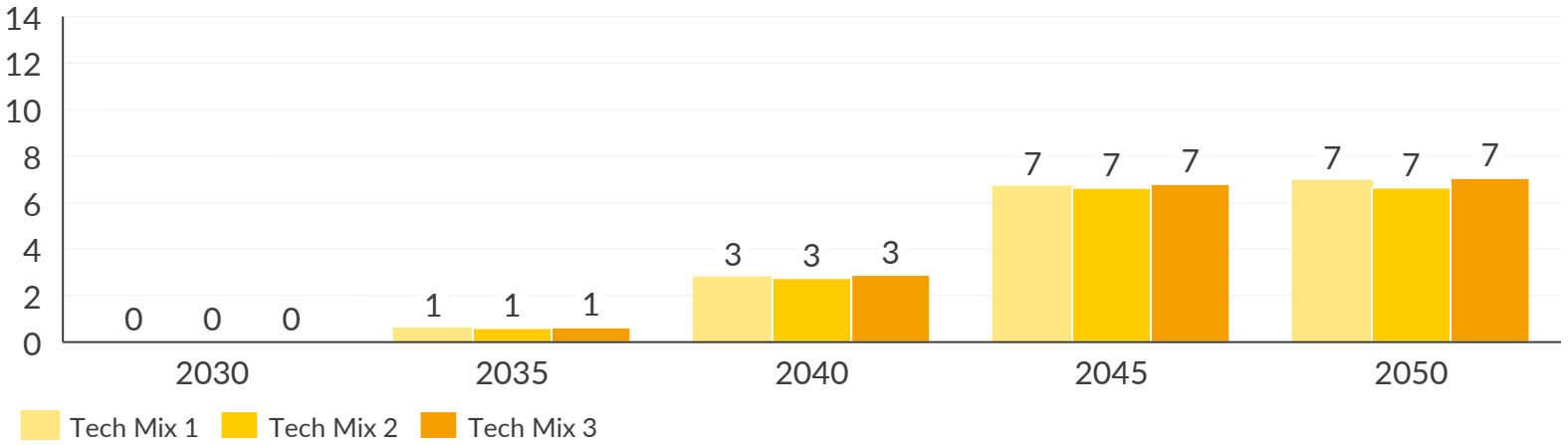
OPTIMAL PROFITABILITY

Hours of Loss of Load per year



Hours of loss of load rise quickly already in the 2030s, as the base case assumes phase out of thermal capacities, e.g. restriction of gas plants to meet CO_2 targets on top of lifetimes of some plants ending

Maximum Loss of Load in a given year



Comments

- By 2030, no loss of load occurs for either of the technology mixes
- The number of hours quickly rises for all technology mixes to ~8-9 hours of loss of load by 2035 – after that it only rises slightly to ~10 hours by 2050
- The maximum peak loss of load rises steadily from ~1 GW by 2035 to ~3 GW and stabilizes around ~7 GW by 2045
  - While the number of hours stay constant, the missing capacity in these hours rises over time, as thermal capacities are removed
- The analysis is conducted with a maximum market price of ~3k €/MWh that arises when loss of load occurs – with a higher price of e.g. ~10k €/MWh a different result might occur
  - Given the increased prices, more capacities could operate profitably or more demand would have incentive to flexibilize, which would lower loss of load
  - Given the public attention of current prices of few hundred €/MWh, prices of ~10k €/MWh seem rather unliekly at this point

1) Assumes ~3k €/MWh as price when LoL occurs

Source: Aurora Energy Research

To achieve scenarios where assets can operate profitably, higher baseload prices need to be incurred – while system costs remain lower

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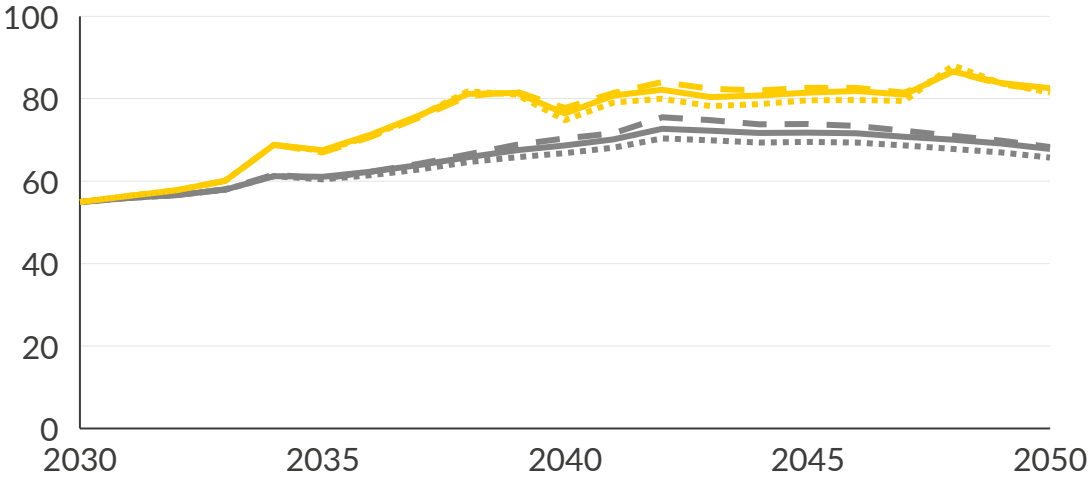
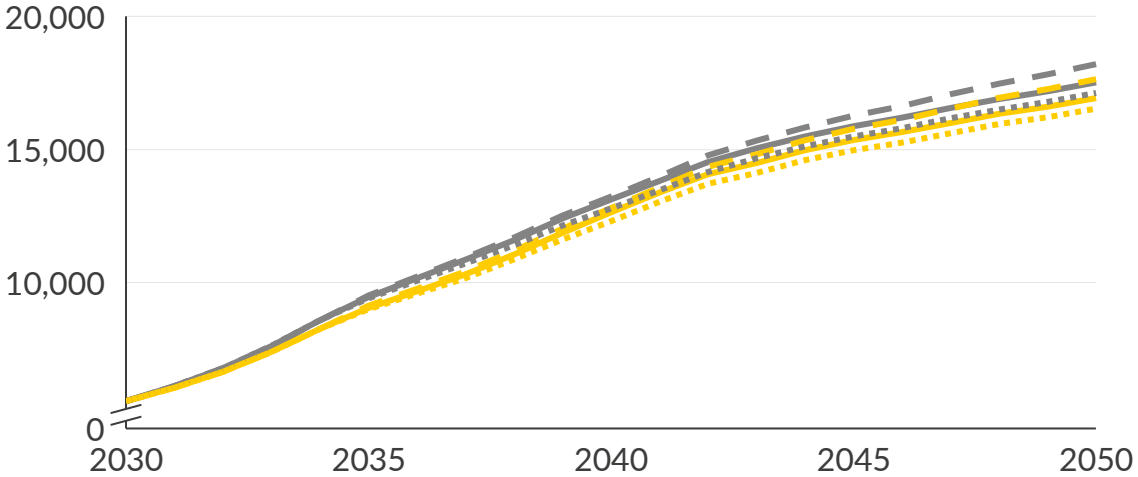
Baseload prices
€/MWh (real 2020)



- Baseload prices are strongly affected by the amount of back-up capacity in the system; when the capacity mix is tight prices go further up in high priced hours and sometimes get to the maximum market cap of 3000 €/MWh.
- Price delta's between technology mixes are less strong. They are driven by differences in variable cost of long duration capacity and back-up. Tech mix 3 has lowest prices, as BECCs are highly profitable to operate, with negative variable costs. Tech Mix 2 has highest prices, even though nuclear has lower variable costs than H_2 CCGT, which is driven by the higher variable costs of its E-methane OCGTs vs H_2 OCGTs.

System cost proxy[1,2]
mio€ (real 2020)



- System costs are higher for Full Security of Supply, as the higher back-up capacity drives up CAPEX and fixed O&M costs, explaining the yearly delta of up to ~590 mio€/year in 2050 with the Optimal Profitability scenarios
- Loss of Load costs of 3000€/MWh are added to the optimal profitability scenarios which reduces the delta between both scenarios[3]
- From the technology mixes the nuclear scenario is the most expensive one, mostly driven by the high CAPEX of nuclear plants compared to the other long duration technologies, which the low variable costs do not fully make up for
- The strong performance of Tech Mix 3 arises from the high profitability of BECCS, which is further covered in the next slides

TM1 - Full sec. of supply | TM1 - Opt. profitability | TM2 - Full sec. of supply | TM2 - Opt. profitability | TM3 - Full sec. of supply | TM3 - Opt. profitability

1) System Costs means the sum of Capital Costs, Finance Costs, Operation and Maintenance Costs, and Commodity Costs. CAPEX from before 2030 are not taken into account here. 2) Annualized costs for the respective year 3) ~300 GWh of loss of load occur over the whole period in the optimal profitability scenarios. That is 900 mio€ using 3k €/MWh as cost, or 45 mio€/year if spread out evenly.

Source: Aurora Energy Research

With less back-up, more loss of load and higher baseload prices, also capture prices for RES are higher in the Optimal Profitability scenarios

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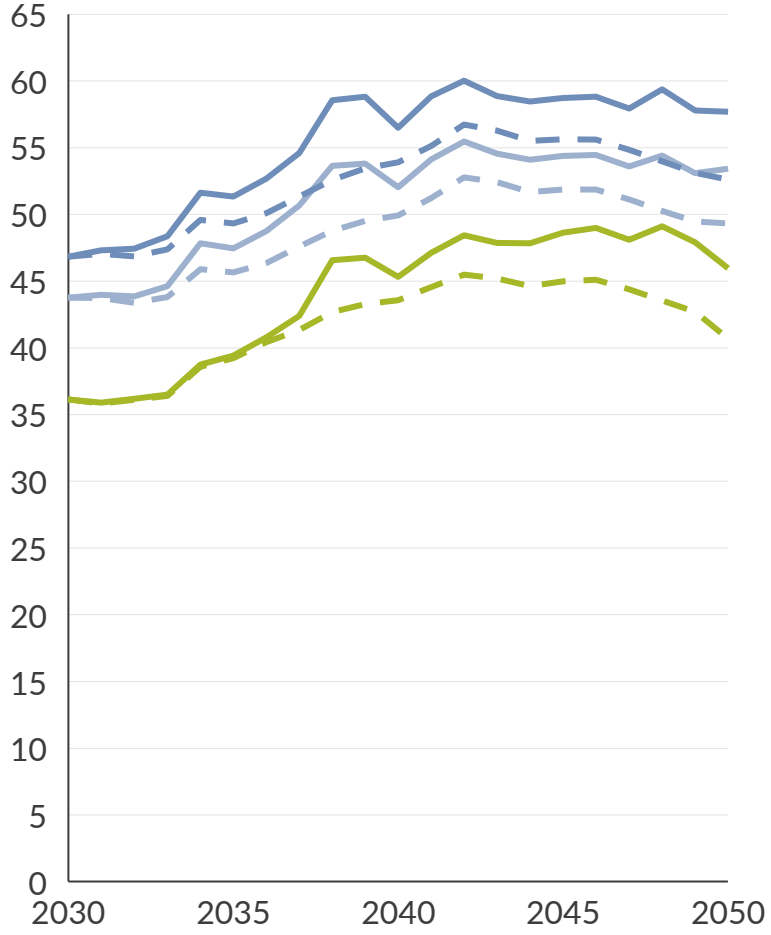
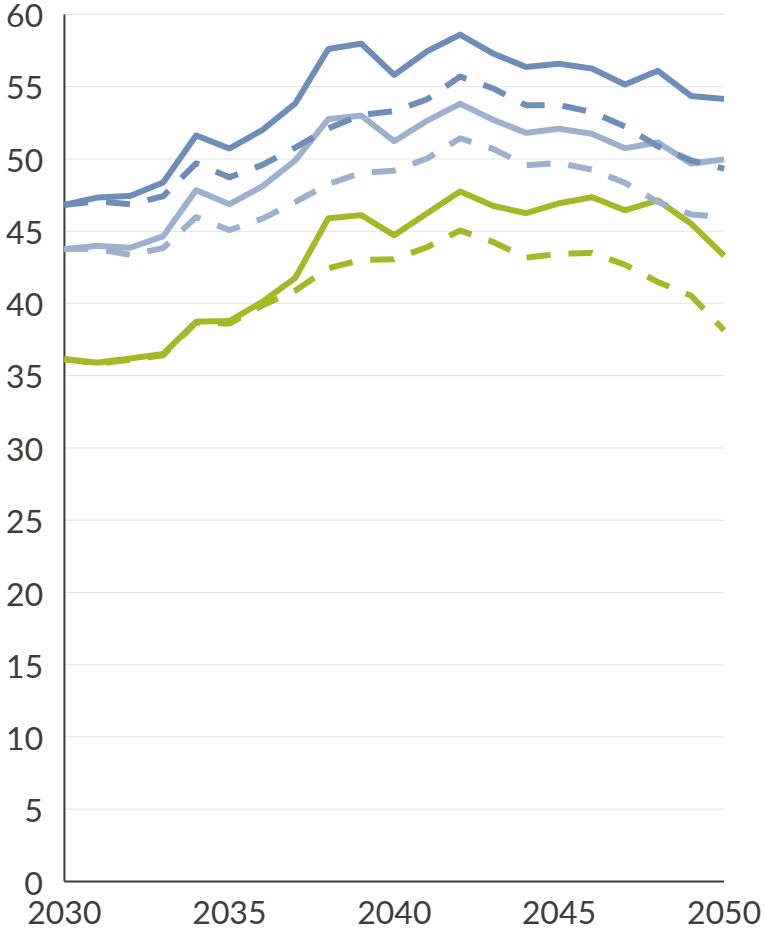
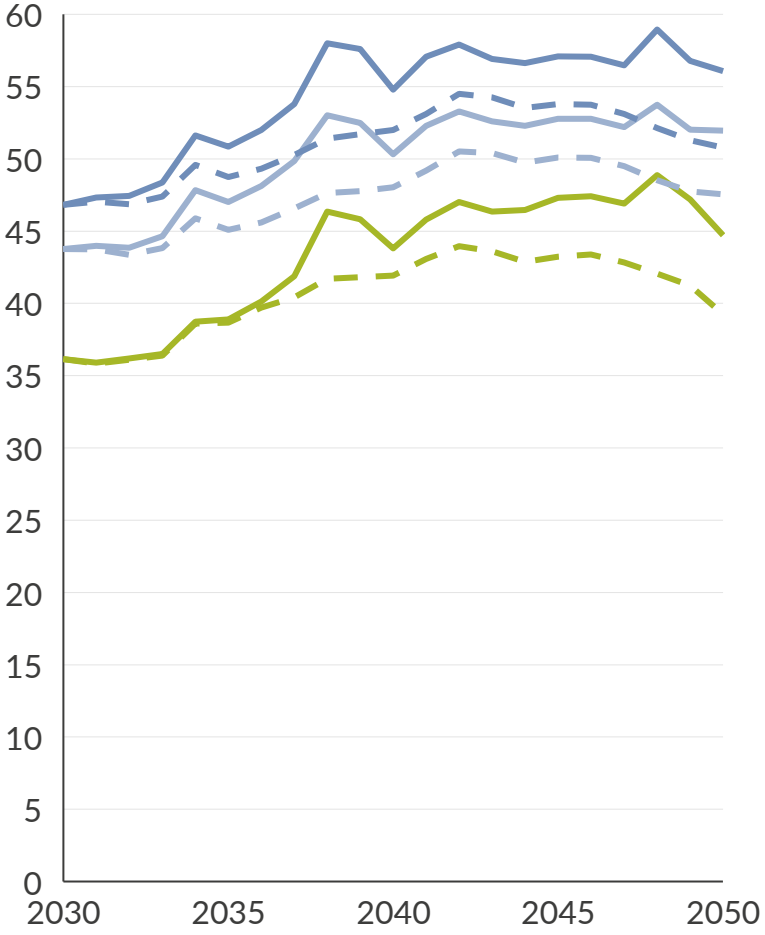
Capture prices – Tech Mix 1
€/MWh (real 2020)



Capture prices – Tech Mix 2
€/MWh (real 2020)



Capture prices – Tech Mix 3
€/MWh (real 2020)



Offshore Wind | Onshore Wind | Solar | Full sec. of supply | Opt. profitability

1) System Costs means the sum of Capital Costs, Finance Costs, Operation and Maintenance Costs, and Commodity Costs. For this analysis all variable costs are taken into account, but only the fixed cost of the long-duration, short-duration and back-up capacity is taken into account. This will not affect the difference between scenarios, as all other fixed costs are the same in all scenarios. In the final report, the total fixed cost will be used to place numbers in perspective.

Source: Aurora Energy Research

For Tech mix 1, no technology can achieve profitability with Full Security of Supply –with less back-up, most plants are profitable starting 2037

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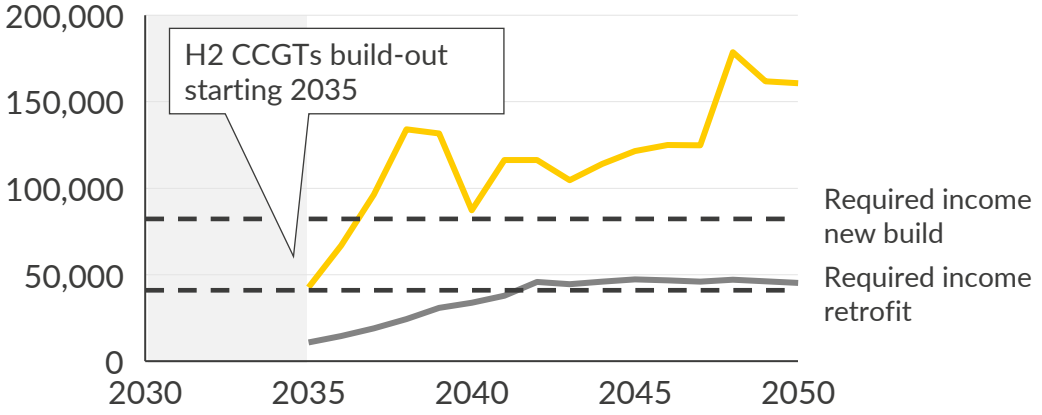
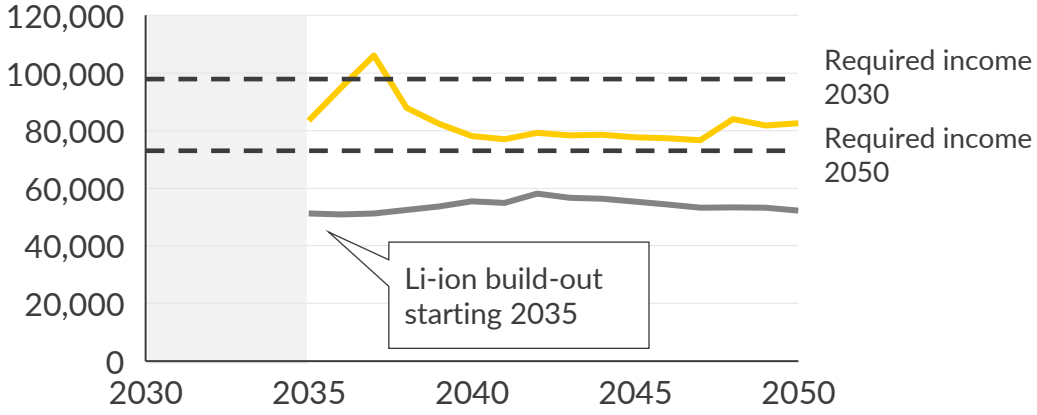
H_2 CCGT margins[1] – Tech Mix 1
€/MW/year (real 2020)



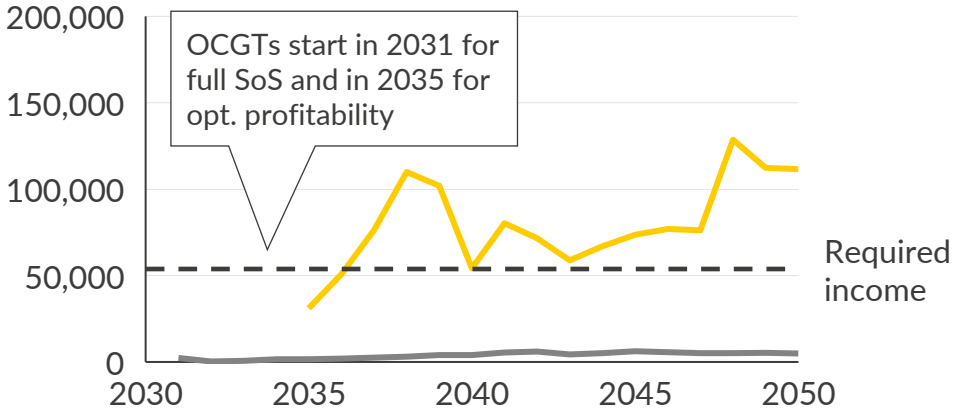
Li-ion (newbuild) margins[1,2] – Tech Mix 1
€/MW/year (real 2020)



Comments

- Optimal Profitability scenario:
  - H_2 CCGTS become profitable by 2037– from then on their margins are consistently above the income a newbuild CCGT needs to earn, by 2050 their margins are even twice as high
  - Li-Ion batteries becomes profitable only in the 2040s – this is because of cost improvements that lower the required income over time, while margins stay nearly constant
  - H_2 OCGTs follow CCGTS – they break-even in 2037 and remain profitable
- When aiming for security of supply, no technologies can achieve the required incomes for newbuild assets

H_2 OCGT (newbuild) margins[1] – Tech Mix 1
€/MW/year (real 2020)



Full security of supply — Optimal profitability

1) The margin reflects the net result from of revenue minus variable cost on the wholesale market. 2) For batteries, beyond the wholesale market, revenues from imbalance markets can be expected

Source: Aurora Energy Research

For Tech Mix 2, when SoS is ensured, the technologies cannot operate profitably – first technologies break-even in 2037 with less back-up

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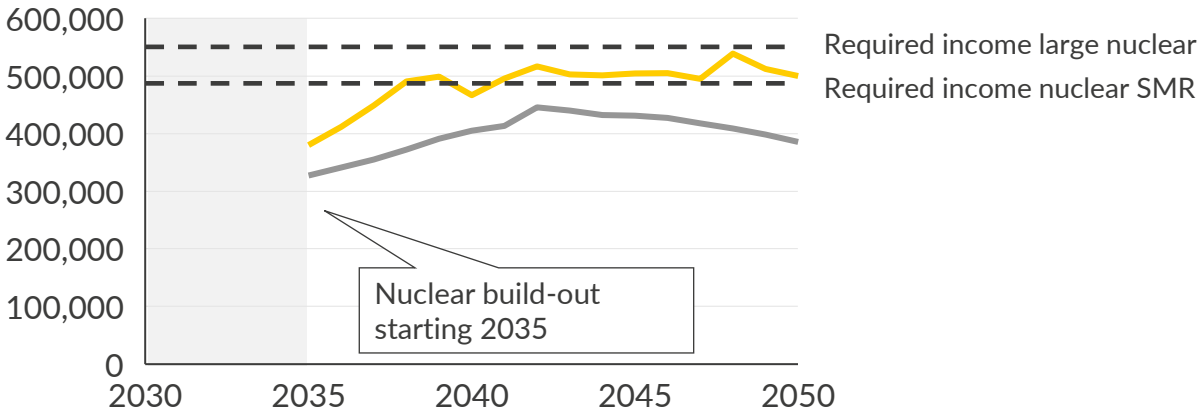
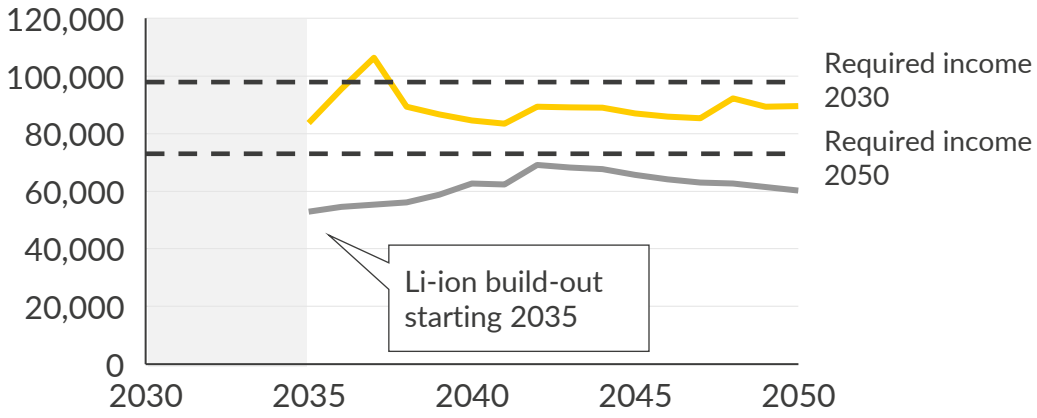
Nuclear (newbuild) margins[1] – Tech Mix 2
€/MW/year (real 2020)



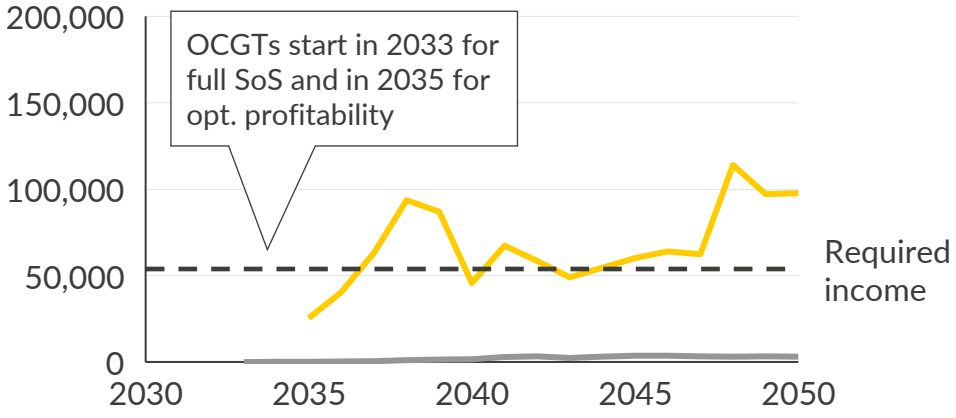
Li-ion (newbuild) margins[1,2] – Tech Mix 2
€/MW/year (real 2020)



Comments

- Optimal Profitability scenario:
  - Nuclear SMRs become profitable by 2037 and from 2041 on their margins are consistently above the income
  - Li-Ion batteries become profitable only in the 2040s – this is because of cost improvements that lower the required income over time, while margins stay nearly constant
  - E-Methane OCGTs break-even by 2037 – after 2045 their margins stay consistently above the required income
- When aiming for security of supply, no technologies can achieve the required incomes

E-methane OCGT (newbuild) margins[1] – Tech Mix 2
€/MW/year (real 2020)



Full security of supply — Optimal profitability

1) The margin reflects the net result from of revenue minus variable cost on the wholesale market. 2) For batteries, beyond the wholesale market, revenues from imbalance markets can be expected

Source: Aurora Energy Research

For Tech Mix 3, rising carbon prices let BECCS becomes profitable in both scenarios – batteries and back-up perform similarly as in other Tech Mixes

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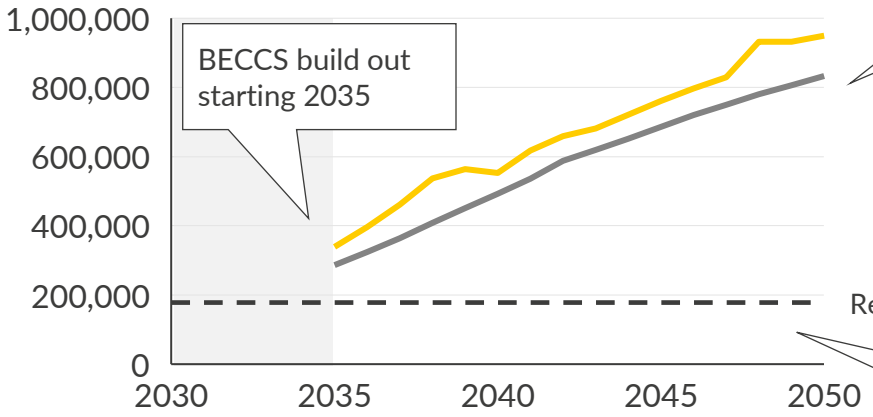
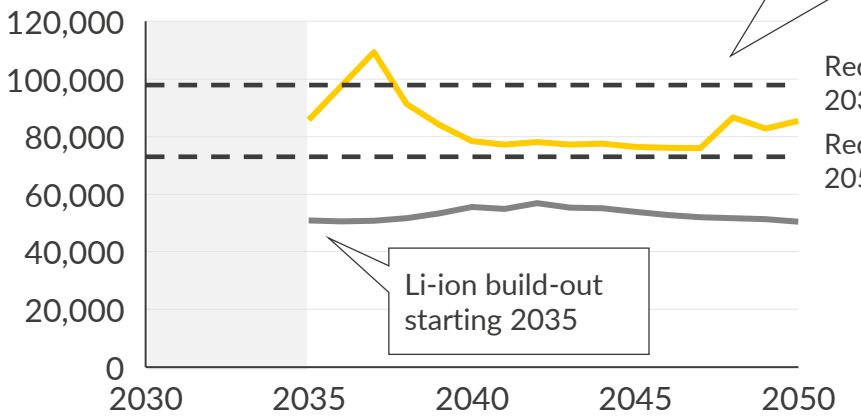
BECCS (retrofit) margins[1] – Tech Mix 3
€/MW/year (real 2020)



Rising carbon prises result in high profitability of BECCS.

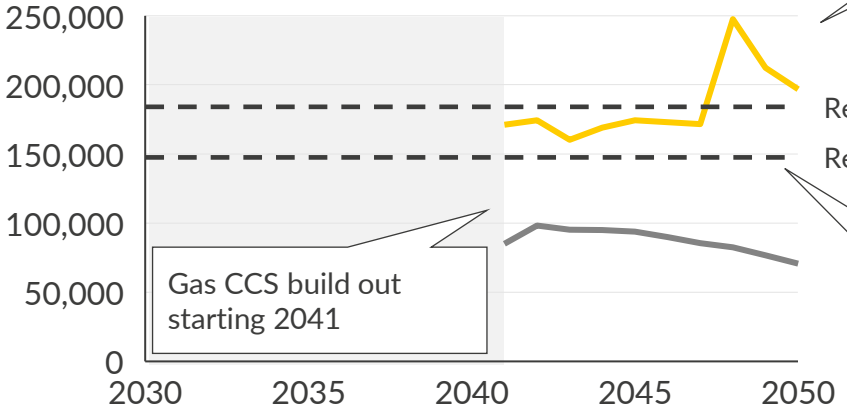
Long duration covered by two techs due to limited availability of biomass for BECCS

Li-ion (newbuild) margins[1,2] – Tech Mix 3
€/MW/year (real 2020)



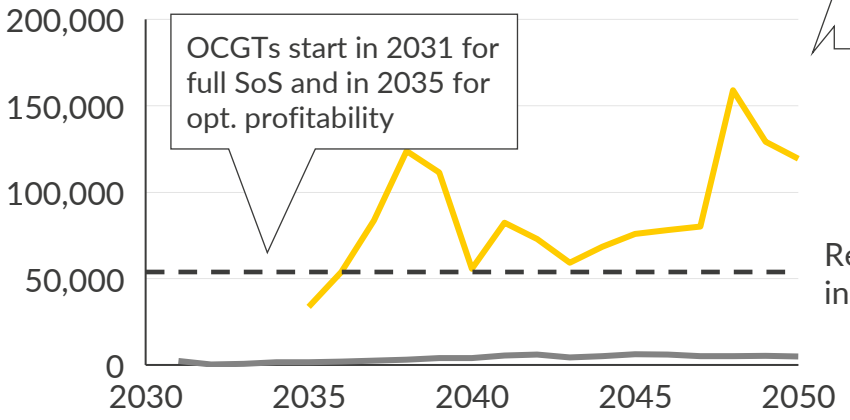
Li-Ion becomes profitable latest in 2050

Gas CCS margins[1] – Tech Mix 3
€/MW/year (real 2020)



Gas CCS profitable for retrofitted plants starting from build out. Not profitable for full SoS.

H_2 OCGT (newbuild) margins[1] – Tech Mix 3
€/MW/year (real 2020)



H2 OCGTs make more than double their required income in 2050

Full security of supply — Optimal profitability

1) The margin reflects the net result from of revenue minus variable cost on the wholesale market. 2) For batteries, beyond the wholesale market, revenues from imbalance markets can be expected

Source: Aurora Energy Research

(1/2): The Optimal Profitability scenario deviates from the Full Security of Supply scenario mainly in the most expensive hours…

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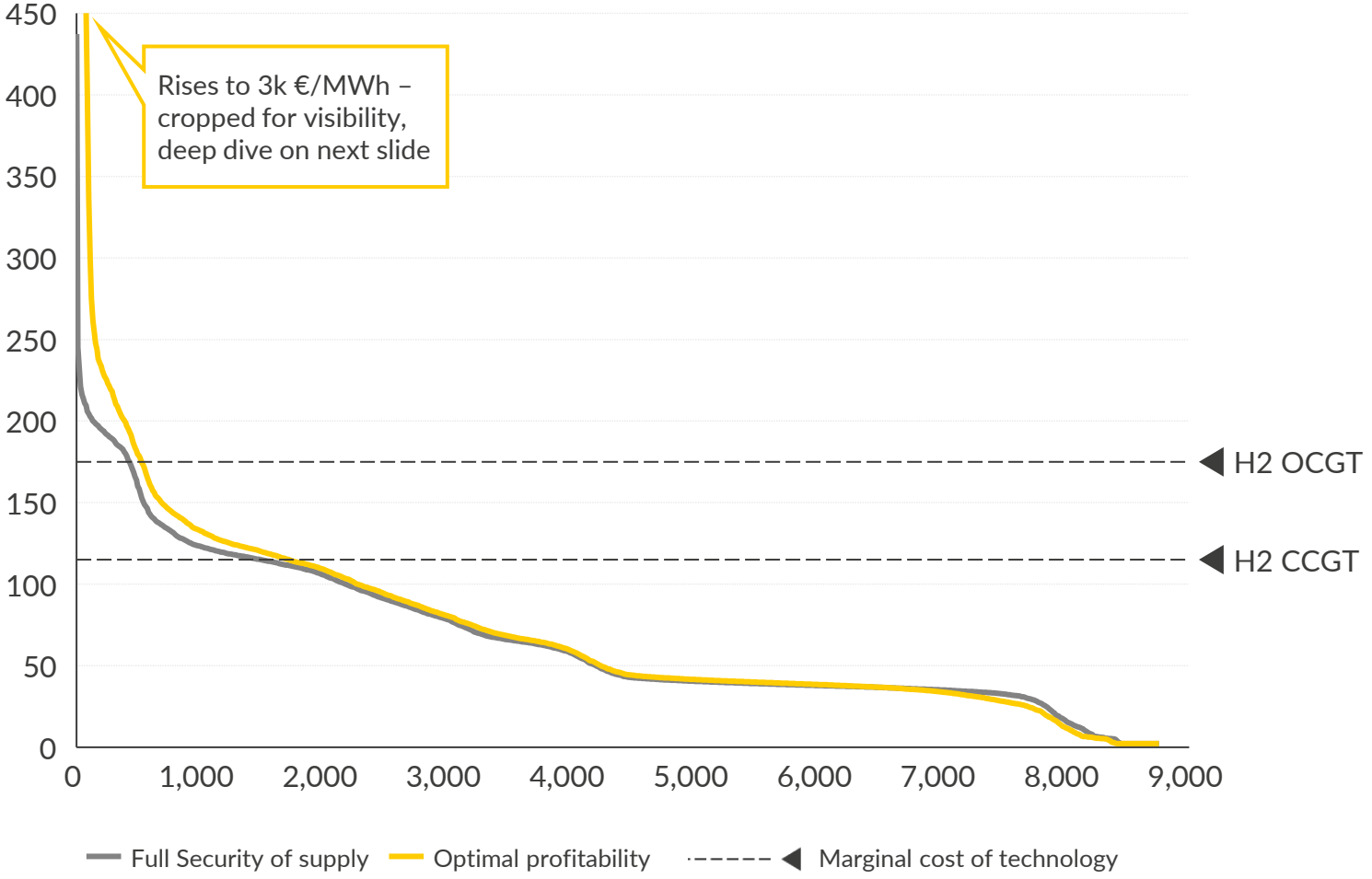
Tech Mix 1

Price duration curve in 2050 – Full year
€/MWh



Comments

- Sorting hourly prices from most to least expensive, the scenarios (Full Security of Supply, Optimal Profitability) exhibit fairly similar power price – except for the most expensive 2,000 hours
- The Optimal Profitability scenario then deviates and starts to show much higher power prices, as expensive DSR becomes active and loss of load occurs
- Whenever the price is higher than the marginal cost of a technology, the plant will produce electricity in this hour
- The area between the power price and the marginal cost lines of the respective technology correspond to the gross margins of the technology
- Especially long-duration flex with high marginal costs and back-up flex strongly benefit from the additional revenues that can be achieved in the few hundred high-price hours
- Technologies with low marginal costs (e.g. nuclear SMRs with ~23 €/MWh, BECCS with ~-46 €/MWh) can produce most hours of the year – not shown for simplification

Note: Prices taken exemplary from Tech Mix 1

Source: Aurora Energy Research

(2/2): … which have a strong impact on technology profitability: Taking back-up as an example, their gross margins rise visibly

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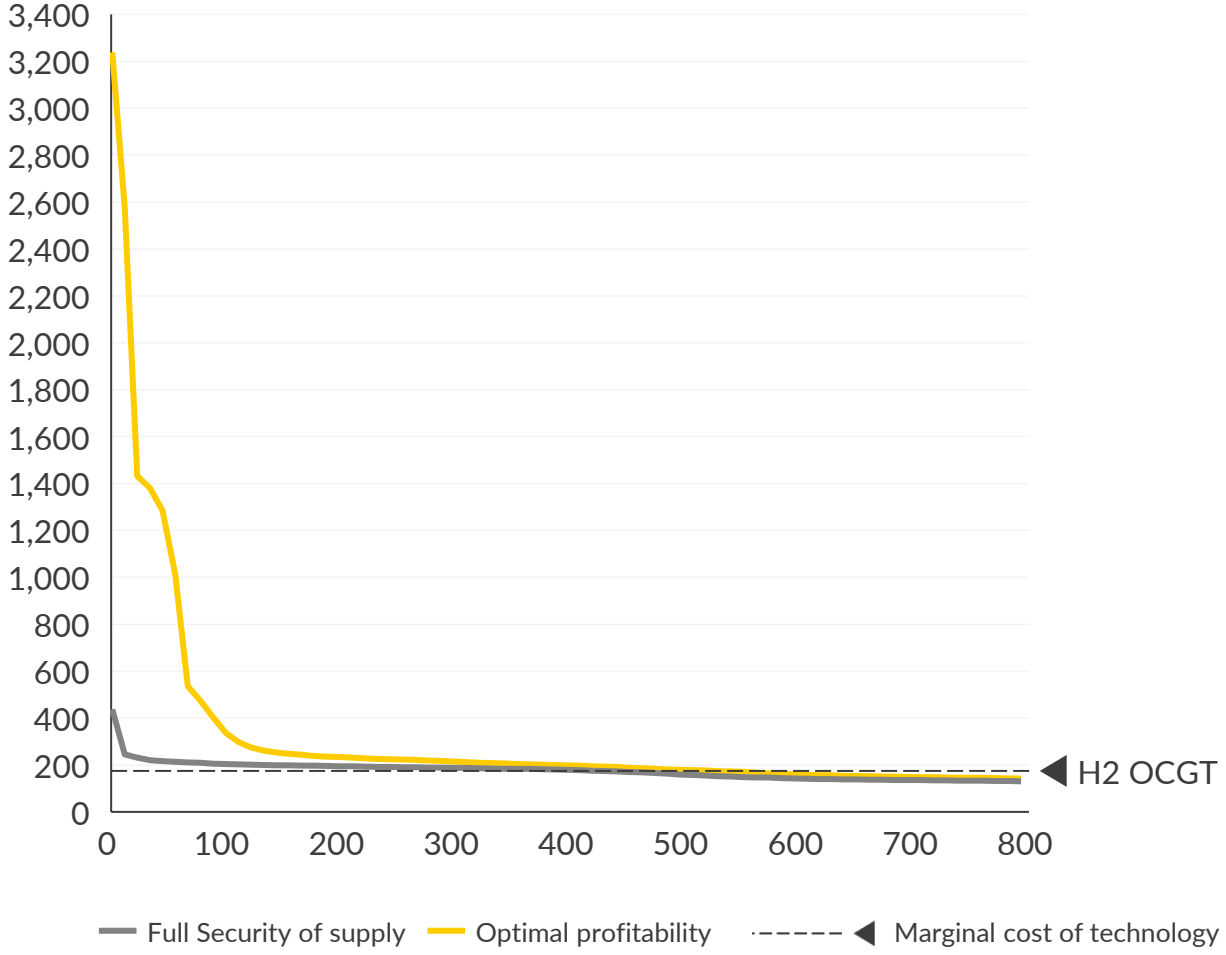
Tech Mix 1

Price duration curve in 2050 – Most expensive 800 hours
€/MWh



Comments

- Compared to the slide before, only the most expensive 800 hours for both scenarios are shown here – also, for simplicity, only back-up are shown
- Again taking the area between marginal costs and prices as an approximation for gross margins, it gets clear why there is a strong margin increase with the Optimal Profitability scenario
  - In the Full Security of Supply scenario, the back-up mostly produce when they are price-setting themselves
  - This leaves barely any margins
  - With the Optimal Profitability scenario, more expensive technologies (DSR) switch on or loss of load occurs – even the expensive back-up now can generate high gross margins
- The same effect occurs for long-duration flex technologies – yet it is relatively less important, as they were already generating sizeable gross margins before

Note: Prices taken exemplary from Tech Mix 1

Source: Aurora Energy Research

Due to persistence in power prices and limited storage duration, batteries cannot fully exploit power price volatility

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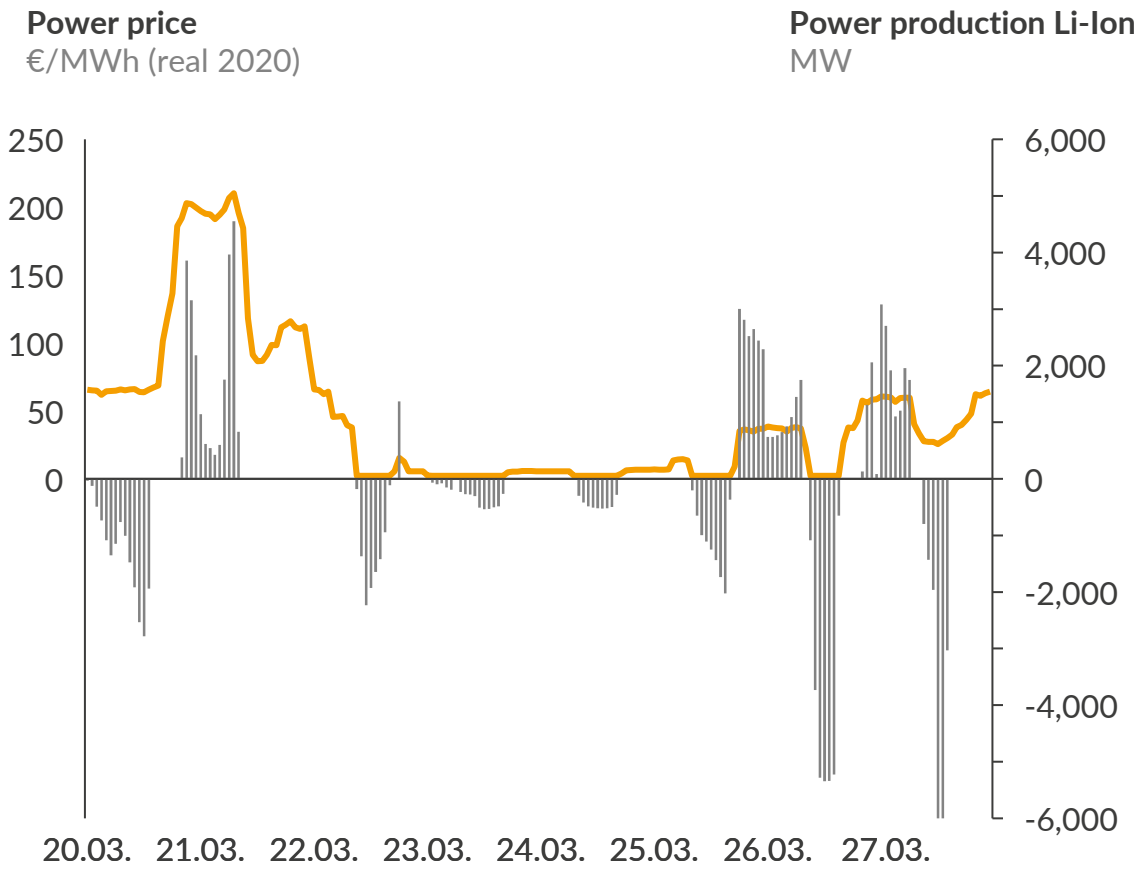
Tech Mix 1

Battery behavior – Exemplary Week 2050



2050 Full Year	Charging	Discharging
Full load hours h	834	750
Average Price €/MWh	36 *("average buy")*	110 *("average sell")*
Theoretical Optimum €/MWh	7 *("least expensive hours")*	177 *("most expensive hours")*
Delta €/MWh	*29* *("overpaid")*	*67* *("undersold")*

Comments

- Given the limited storage duration of batteries as well as the actual price patterns (prices do no oscillate from low to high from hour to hour), there is a limit of how much of price fluctuation batteries can capture
- On average, batteries are losing a spread of ~100 €/MWh versus the theoretical optimum – that means versus a situation where they could exploit the combination of the least and most expensive hours, without being restricted by finite storage depth

Note: Based on Tech Mix 1, Full Security of Supply scenario

Source: Aurora Energy Research

There is enough CCGT capacity in the Netherlands to cover the H_2 CCGT build of Tech Mix 1 through retrofitting

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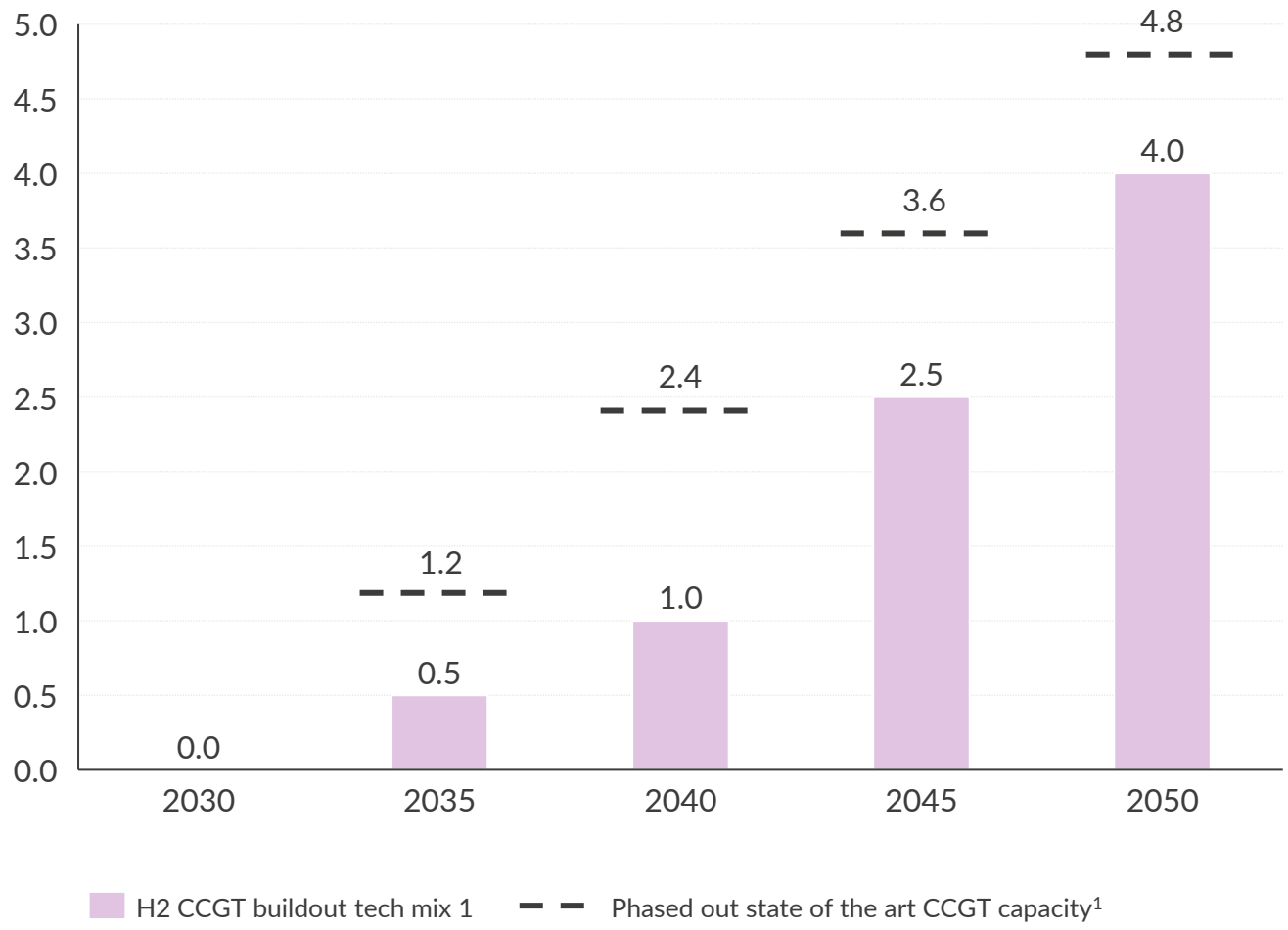
Tech Mix 1

H2 CCGT build out in tech mix 1 vs. phased out state of the art CCGT capacity[1]
GW



Comments

- In technology mix 1, the long duration flex is provided by hydrogen CCGTs, which build up to 4 GW of capacity
- In the Full Security of Supply scenario, the margins for the plants are high enough to support retrofitted H_2 CCGTs from 2040 onwards, but to be able to do so enough gas CCGT capacity needs to be available for retrofitting
- In the Netherlands there is currently a total of 4.8 GW of CCGT capacity that was build after 2010, which could potentially be suitable for retrofitting
- To reach Net Zero in 2050 and intermediate targets, the capacity is restricted with the capacity as show above
- It is enough to allow all build out in tech mix 1 to be based on retrofitted plants, however, the lifetime of these plants would be limited

1) State of the art defined as all CCGT capacity build post 2010, phased out to reach Net Zero

Source: Aurora Energy Research

Hours of loss of load (~10x) and maximum loss of load (~2x) rise strongly, when switching to an extreme weather year

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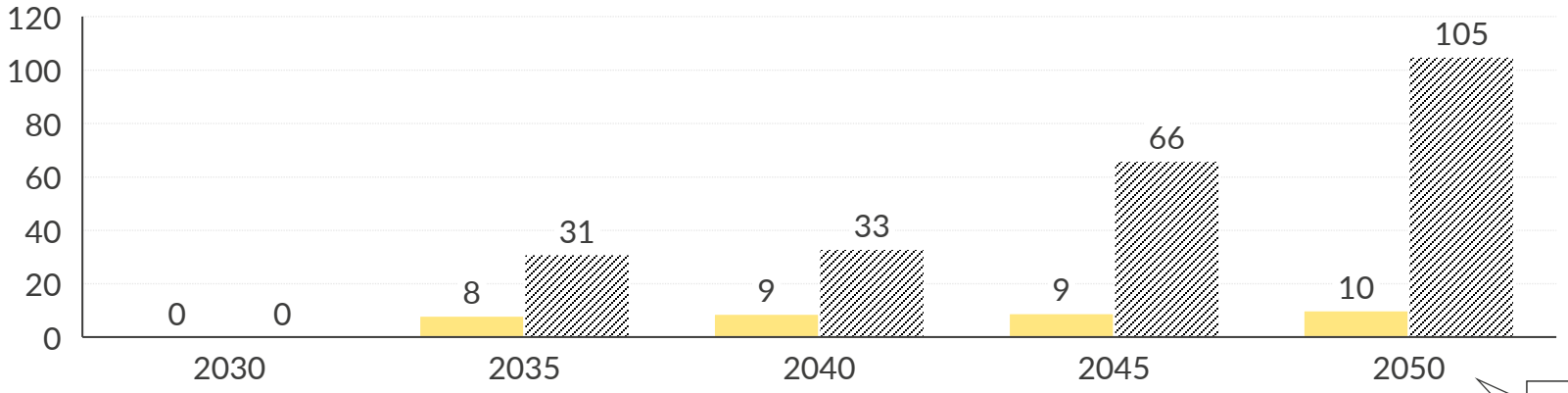
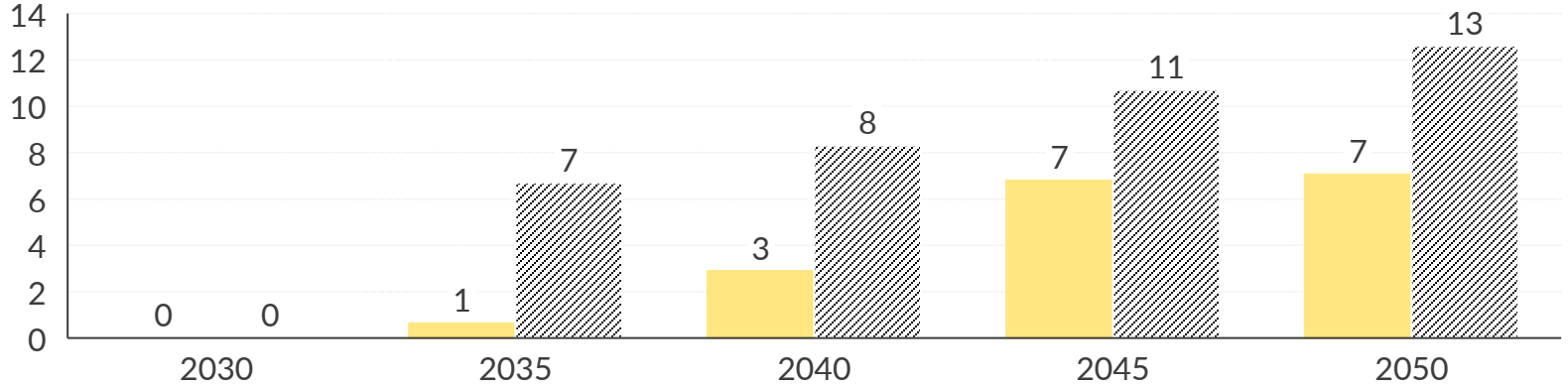
Tech Mix 1 | **OPTIMAL PROFITABILITY**

Hours of Loss of Load[1]
h



Maximum Loss of Load[1]
GW



Standard Weather Year (2013) | Extreme Weather Year (2006)*

Data exemplary for Tech Mix 1 – development in Tech Mix 2 and 3 similar

Comments

- Hours of loss of load rise strongly when switching from the standard weather year (2013) to a more extreme weather year (2006)
  - Already in 2035, they are ~4 times higher at 31 hours
  - By 2050, with 105 hours of loss of load, they would rise by >10
- Also the maximum peak loss of load rises, even though not in the same magnitude
  - While in 2035 the maximum peak is already much higher at ~7 GW, the value stabilizes at ~2 times what it was before and ~13 GW maximum peak loss of load in 2050

1) Assumes ~3k €/MWh as price when LoL occurs; 2) Chosen as WY 2006 exhibited the highest maximum peak loss of load

Source: Aurora Energy Research

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Introduction: Package D

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This section, *Package D*, serves to provide an **overview** of the **non-economic hurdles** (i.e. all hurdles which are not unprofitability) for the most promising CO_2-free flexible technologies identified in *Package B*, as well as **suggested potential high-level solutions**[1] to these hurdles and **estimated lead-in times** for implementation of the first ~1 GW of each technology

Promising CO_2-free flexible technologies (per category)

Technologies were identified as 'promising' if they fulfilled at least one of the following criteria:

a) Steep predicted cost-reduction curve
b) Proven viability in neighbouring markets
c) Small step to profitability (or already profitable)
d) High suitability to the system's needs, e.g. in terms of duration, flexibility

		Criteria			
		a	b	c	d
Biofuels	▪ Biogas ▪ Biomass			● ●	●
Carbon Capture	▪ BECCS ▪ CCS			● ●	
New-fuel CCGTs	▪ H_2 CCGT ▪ E-methane CCGT	● ●		● ●	● ●
Nuclear fission	▪ Conventional large-scale ▪ Small Modular Reactors (SMR)	 ●			●
Li-ion batteries		●	●	●	●
Flexible household demand	▪ Flexible EV charging ▪ Flexible heat pumps ▪ Bidirectional EV charging ('V2G')		●	● ● ●	● ● ●
Flexible industrial demand	▪ Flexible power-to-heat (electric boilers) ▪ Flexible electrolysis	 ●		● ●	● ●

Hurdle categories

Four main hurdle categories were identified, which are treated separately for each technology group in the group's respective deep-dive. Of the *Market design and regulations* category, the *Tariffs and taxes* subcategory was sufficiently substantial to name its respective hurdles separately in the overview section.

Note that all relevant hurdles to current deployment are named, including necessary future developments that are already planned or highly likely to occur.

Political support & market coordination	▪ Public or political concerns or unpopularity ▪ Uncertainty surrounding the direction other market participants, incl. gov't, will take
Availability constraints	▪ Poor fuel availability ▪ Insufficient or lacking infrastructure ▪ Actual or possible resource shortages
Market design & regulations	▪ Maladaptation of regulations or the market to the technology in question (e.g. poor incentives) ▪ Missing market structures or definition
↳ Tariffs & taxation	▪ Maladaptation of (grid) tariffs and taxation to the technology in question (e.g. poor incentives)
Technological market readiness	▪ Technological immaturity for full commercial deployment, or lack of availability

1) The potential solutions suggested per technology group are presented as ideas to further the debate pertaining to CO_2-free flexible energy technologies, not as concrete proposals for stimulating their uptake. The suggested solutions are in no way binding and do not necessarily represent the opinion of the Dutch Ministry of Economic Affairs and Climate ('EZK') or any of the other stakeholders involved in this project. Aurora does not guarantee completeness of the list of potential solutions, nor that implementation of any of the solutions, alone or in combination, will solve the problem at hand.

The success of many technologies depends on the government playing a coordinating role

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Will the technology options also satisfy other societally important criteria (e.g. environment, resource competition, safety)?

Zero-carbon technologies may have other societal impacts or risks, such as radioactive waste and the low-probability but high-impact risk of a nuclear explosion (nuclear fission), competition for agricultural resources (biofuels), the risk of methane leakage (e-methane), or local hazardous and odorous emissions (biogas). Public acceptance of these technologies depends in part on how the government addresses these factors.

How large a role will hydrogen play in the future Dutch economy? Will there be a hydrogen transportation grid?

For market participants to invest in hydrogen, certainty is needed that a hydrogen infrastructure and ecosystem will come into existence with sufficient supply, demand, and transportation capacity, and sufficient renewables generation to power the necessary electrolysis. Otherwise, a coordinative 'chicken and egg' problem may arise, as all parties wait to see whether the market will shift substantially to hydrogen or opt for other solutions, such as gas with CCS or electrification.

Further uncertainty surrounds the evolution of hydrogen in other countries, with imports and exports poised to play a large role should they become available.

To what extent will the electricity grid be reinforced?

The practical feasibility of multiple aspects of decarbonisation – increased RES generation and electrification in particular – depends on the capacity of the electricity grid to handle them. Although flexibilisation of electricity demand can help reduce congestion, the success of the electrification that enables much of such flexibilization – e.g. electric industrial boilers – depends nonetheless on increased grid capacity.

Will the necessary energetic resources (fuels, electricity, organic matter) be available?

For many of the technologies analysed, the availability of the necessary energetic inputs is uncertain. This is true for new-fuel CCGTs (both low-carbon H_2 and e-methane have little production in the Netherlands), electrolysers (low-carbon generation demands high levels of renewable electricity generation), and perhaps most especially biofuels (fuel crops risk competing with agricultural needs, and environmental concerns surround the use of purpose-cut wood for power generation).

How will the regulatory landscape develop?

Unadapted grid tariffs and taxes still form a hindrance to the deployment of certain decarbonisation and flexibility technologies. How the structure of markets, tariffs, taxes, and regulations develop will play an important role in shaping the future energy system.

Source: Aurora Energy Research

Overview of non-economic hurdles per technology

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	Biogas CCGT	Biomass	BECCS and CCS	H_2 CCGT	E-methane CCGT	Nuclear fission plant	Li-ion batteries	Flexible household demand[1])	Flexible power-to-heat	Flexible electrolysis
Political support & market coordination	Low acceptance due to smell	Uncertainty: future political support	Volatile support; safety concerns	Uncertainty: future power system, H_2 imports, CCS acceptance	Uncertainty: future power system, H_2 imports, CCS acceptance	Political commitment necessary; safety concerns; impact on future power system		No market/price incentive at the distribution level		Uncertainty: future power system (RES, H_2 demand, grid)
Availability constraints: fuel, resources, infrastructure	Limited production facilities; resource competition	Possible resource competition; uncertainty: future fuel availability	Possible spatial constraint due to demands from other countries	Low H_2 availability; no H_2 infrastructure	Low H_2 availability; low e-methane availability	Grid requirements; NIMBY concerns	Growing demand; import dependence; rare earth metal scarcity	Possible grid congestion		Little RES; no H_2 infrastructure
Market design & regulations			CCU could be further incentivised	No H_2 market	No H_2 market		Balancing market not well attuned	Static household electricity prices; third-party access		No H_2 market
→ Tariffs & taxation				High grid fees (for electrolysis; but blue H_2 also possible)	High grid fees (for electrolysis)			Static household electricity fees	High and inflexible grid fees	High grid fees
Technological market readiness						High lead times; SMR not yet available; few parties with know-how		Technologies exist at small scale; no integrated solutions yet available		PEM electrolysers not yet scaled up

Severity of hurdle: Mild | Intermediate | Severe | Present-day hurdle | Future hurdle[2]

1) Includes: (i) smart/flexible EV charging, (ii) smart/flexible heat pumps, (iii) bidirectional EV charging, i.e. vehicle-to-grid. 2) For many of the future hurdles (e.g., hydrogen infrastructure development), plans to address them are already being made.

Source: Aurora Energy Research

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The uncertainty around fuel availability for biomass and biogas installations could be resolved through political commitment

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Infrastructure, fuel, and space availability

The potential for increased availability of biogas and biomass is uncertain and likely limited. This is due both to physical limitations themselves and to political and public opinion pertaining to these limitations and the acceptability of the use of certain resources.

Biogas[1]

- **Few production facilities for biogas** are available in the Netherlands
- **Competition with agricultural resources** — both land for growing crops as well as the use of certain crops themselves — strongly limits the amount of resources considered acceptable to divert to biofuels, as doing so can reduce the availability of food crops and drive up prices
- **Suitability of low-pressure gas grids** for the injection of large volumes of biogas is limited in some cases

Biomass

- **Future/increased availability of biomass may be restricted** by sustainability and environmental criteria pertaining to forests, domestic forestry policy of biomass producers, increased demand across the board from decarbonising countries, and the Netherlands' willingness to import large amounts

Potential solutions

Biogas

- **Clear allocation of space** for biogas production could resolve the problem of spatial competition
- **Stringent standards limiting competition with agricultural demands** by biofuels should be put in place
- **Priority should be given to by-product or waste biogas** — e.g. from agricultural or domestic waste streams – as these do not compete with other demands
- **A gas grid upgrade** may be needed for the widespread use of biogas

Biomass

- **Clear regulatory commitments** should be made pertaining to the admissibility of biomass and the environmental standards to be applied

1) To date, most biogas plants are either engine-based or steam turbines.

Sources: Aurora Energy Research, Energeia

Biogas is subject to availability concerns, which could be allayed through research and planning

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Technological market readiness

Biogas[1] and biomass assets are technologically mature

Biogas

- **The technology is viable**[2] but has not been rolled out at scale

Potential solutions

Biogas

- **Increased efficiency of conversion**, through improvement of existing technologies or the development of yet-immature options such as supercritical gasification, could help with resource constraints

Political support & coordinative uncertainty

Evolving political sustainability requirements and low support remain a concern for both biomass and biogas

Biogas

- **Leakages of this greenhouse gas** carry the risk of negating carbon emission reductions through their impact on global warming, as noted for *e-methane*
- **Acceptance of biogas production** is low due to its smell, especially in densely populated areas

Biomass

- **Public concerns** exist about the carbon-neutrality of biomass as well as the emitted fine dust, which could damage people's health

Potential solutions

Biogas

- **Prevention and reparation of methane leaks** is already governed by rules in the Netherlands. Applying the Dutch methane rules to companies exporting to the European Union could be the next step.
- In the **planning of biogas production facilities**, it should be acknowledged that they have the greatest chance of success in rural areas

Biomass

- The **sourcing of biomass** should be made more transparent

Expected lead-in time: 0 years

The technologies are market-ready: their success depends on continued political support

.1) To date, biogas assets are mainly either steam turbines or engine-based. 2) For example, one neighbourhood in Breda is heated through a biogas CHP.

Sources: Aurora Energy Research, Energeia

Carbon capture and storage is becoming more heavily subsidised – political coordination seems lacking

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Market design and regulations

- **There is a 'ceiling' to the amount of CCS that can be subsidised** through the SDE++. Recently the ceiling has been raised from 7.2 Mt to 9.7 Mt
- **The utilisation of CO_2 (CCU) is viewed as more desirable than its storage (CCS).** To companies that capture CO_2, however, storage is more attractive than e.g. delivery to greenhouse horticulture. This situation arises because for storage (if by pipeline) companies do not need to pay emission rights, but for delivery (and utilisation) they do. In addition, SDE++ subsidies make CCS comparatively attractive.

Potential solutions

- **A further increase of the ceiling** (or removal thereof) would help the rollout of CCS projects (but might come at the detriment of other carbon-abating technologies)
- **An additional three billion euros will be reserved for sustainable technologies**, as announced by the cabinet on 21 September (*Prinsjesdag*). A substantial portion of that amount will likely flow towards CCS
- **A pilot to increase the levels of carbon utilisation** has shown promising results; it suggests an administrative system to enable more carbon to be delivered to greenhouse horticulture in the summer and more to be stored in the winter[1]. More research into buffering such fluctuations would be necessary to roll the idea out fully

Infrastructure, fuel, and space availability

- **Spatial constraints** may arise from the political undesirability of CCS in Germany. Germany is not against CCS as such, but does not wish to store CO_2 under German waters. Storage under Dutch or Norwegian waters is commonly viewed as the solution, but political coordination surrounding spatial constraints seems to be lacking

Potential solutions

- **An EU-wide plan of the designated areas** for CO_2 storage would shed more light on storage availability and its limitations

1) The pilot revolved around the difference between grey and green CO_2. Short-cycle (green) CO_2 is biogenic and requires no emission rights, in contrast to the CO_2 released in the combustion of fossil fuels. Greenhouse farming only needs CO_2 between March and October, which implies opportunities to administratively offset green and grey carbon. In the summer, both kinds are delivered to greenhouse horticulture; in the winter, both are stored.

Sources: Aurora Energy Research, Energeia

Safety concerns about CCS persist and could be allayed through more research and information

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Technological market readiness

- **CCS using exhaust CO_2 is technologically mature enough** to already be (nearly) economically viable
- **Air-capture CCS is possible but still requires significant development** to be widely market-deployable

Potential solutions

Political support & coordinative uncertainty

- **Political support could be volatile.** In contrast to a fully decarbonised system, CCS is not viewed as an 'end-game' technology, as it does not mitigate the reliance on fossil fuels and production of CO_2, and CO_2 storage capacity is not unlimited
- **Investing in CCS could result in high opportunity costs, stranded assets, or technological lock-in**, due to e.g. the abovementioned factors or if later investment non-CCS based technology proves necessary that could already be made now
- **Safety concerns** around offshore storage of CO_2 include leaks and their impact on ecosystems
  - However, onshore CCS is forbidden since the cancellation of the Barendrecht project due to local pressure

Potential solutions

- **Long-term plans or commitments pertaining to CCS** could help market parties decide whether investments in CCS are worthwhile
- **The safety of carbon storage** could be improved through further research and stringent standards pertaining to its application

Expected lead-in time: 0 years

Carbon capture and storage is market-ready: its success depends on continued political support

Source: Aurora Energy Research

Alongside an unprofitable market structure, H_2 and e-methane CCGTs are hampered by fuel and infrastructure unavailability

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Market design & regulations

- **No hydrogen market** is yet defined in the Netherlands – *see Industrial DSR*
- **Mid-term profitability (i.e. by 2030) is difficult** for high-variable-cost flexibility technologies such as hydrogen and e-methane CCGTs in the current electricity market[1]
  - These technologies will rely largely on revenue from a small number of hours with high scarcity, making their profitability highly sensitive to the level of loss-of-load and scarcity pricing

Potential solutions

- *See Industrial DSR for Potential solutions pertaining to a hydrogen market definition*
- **Measures to increase prices** (and therefore new-fuel CCGT revenue) during hours of scarcity could be considered, such as adding a scarcity price top-up of some kind (c.f. Texas)[2]
- **The regulator could loosen the rules pertaining to loss of load pricing**, allowing prices reached during these moments to rise more quickly

Infrastructure, fuel, and space availability

- **Little yet exists in the way of hydrogen transportation and storage infrastructure** outside of a few industrial clusters: pipelines, conversion/ compression stations for shipping, salt caverns for storage, etc.
- **E-methane only makes sense to synthesise from green hydrogen**, as synthesis from blue hydrogen would amount to an effective methane-to-methane conversion with double conversion losses. However, to green hydrogen most hurdles for flexible electrolysis apply, including:
  - Insufficient renewable electricity generation
  - Limited H_2 availability for conversion to e-methane
- **E-methane synthesis requires a high-concentration CO_2 source**, as direct air capture is still prohibitively expensive and technologically immature
- **Suitability of low-pressure gas grids** for the injection of large volumes of e-methane may be limited in some cases (see section on *Biogas*), placing constraints on the possible locations available for synthesis relative to the gas grid

Potential solutions

- **Hydrogen infrastructure and storage buildout should be prioritised and accelerated** by the government and grid operator, including definition of long-term plans with hard financial backing. To this end, the outgoing government has reserved 750 million EUR for the creation of a hydrogen backbone[3]
- **Methanation co-location with an electrolyser and RES source**[4] could help avoid many of the issues pertaining to electrolysis for e-methane. Both electricity and hydrogen infrastructure shortcomings could then be avoided, as the product could be injected into the natural gas grid. However, proximity to a CO_2 emitter is also necessary, placing restraints on options
- See Potential solutions for *Technological maturity*

1) See *Package B* of this study, where we estimate the profitability of multiple flex technologies in 2030 in a net zero scenario. 2) Such measures are taken by the Electric Reliability Council of Texas (ERCOT). 3) The idea is for Gasunie to invest this amount and recoup it from the market. The govt. covers the risk that demand will not keep pace with supply. 4) Electrolyser co-location may lead to overall system inefficiency, as described in the *Political support & coordinative uncertainty* section pertaining to flexible electrolysers. It is also made more difficult by the need for a cost-effective and climate-neutral source of CO_2, implying colocation with a CO_2 emitter.

Sources: Aurora Energy Research, Energeia

H_2 CCGT lead-in times are likely longer due to the need for H_2 infrastructure, whereas e-methane risks a technological lock-in

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Technological market readiness

- **CCGT power plants are a mature technology** for which adaptations for burning hydrogen or e-methane are currently commercially available
  - New-build natural gas CCGTs now often come 'hydrogen-ready', meaning a conversion would require minimal marginal investment
  - Utilities may need time to build up know-how pertaining to an H_2 supply chain
- **Methanation is a known and demonstrated technology**, provided sources of H_2 and (waste) CO_2, and pilot plants exist for synthesising medium amounts of e-methane[1]
  - However, production would need to be scaled up for sufficient amounts to be available for a CCGT
  - The potential for e-methane synthesis depends on H_2 electrolysis

Potential solutions

- **A forum for knowledge transfer** from industry players already knowledgeable in H2 supply chain logistics (e.g. those using the Port of Rotterdam's H_2 grid) to utilities may help speed up scale-up and learning times
- **Support for scale-up projects for e-methane** synthesis as well as coordinative support for co-location could help to speed up the process

Political support & coordinative uncertainty

- **For the uncertainties surrounding a future hydrogen market** and ecosystem, see *Industrial DSR*
- **Market coordination around e-methane may risk a technological lock-in** onto a fuel less efficient and potentially more expensive than hydrogen (due to conversion losses and the need for CO_2 for e-methane synthesis)
- **Methane is itself an extremely potent greenhouse gas**, so great care would need to be taken that no spillage occurs, which could quickly negate any achieved CO_2 reduction
  - Beyond the direct environmental risk, public opinion may also be impacted, providing a further hurdle

Potential solutions

- **Long-term policy, plans, and financial and infrastructural commitments** pertaining to hydrogen and natural gas/methane would be helpful to address market uncertainties
- **The creation of stringent regulations and supervision** pertaining to leakage prevention for e-methane synthesis may help both prevent unnecessary greenhouse gas emissions and fend off possible public scepticism

Expected lead-in time: 5 - 10 years

E-methane synthesis could be scaled up relatively quickly, as it is mature and has already been demonstrated and researched in multiple projects.[1] Lead-in times for hydrogen CCGTs may be slightly longer, due to the time necessary to create a hydrogen transportation and storage infrastructure as well as a hydrogen market. However, Gasunie plans to have a national H_2 grid ready by 2028, and an H_2 CCGT could feasibly function without such a grid and simply be co-located with its H_2 source.

1) See e.g. Audi's e-gas plant in Emsland and the EU27's Store&Go project, part of the Horizon 2020 programme

Sources: Aurora Energy Research, European Commission

Political commitment to nuclear power is necessary for investors, the TSO and the provinces

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Market design and regulations

- **Political commitment is a prerequisite for investments** in nuclear power
- **High-CAPEX assets potentially becoming stranded** due to future changes in policy or public acceptance pose a high risk

Potential solutions

- **The government would need to guarantee not to impose a nuclear phase-out** within the lifetime of any nuclear units to be built. To the government, such a guarantee would have the additional advantage of not spending substantial sums of money of the closure of these plants once built, as is currently happening to coal plants.

Infrastructure, fuel, and space availability

- **Uranium is no longer mined in any significant amount in Western Europe**, making supplies completely dependent on overseas or long land-route shipment and thus potentially sensitive to geopolitical or trade disruptions
- **The grid infrastructure required** for a power system based on a few large nuclear plants is different from that needed for a system based on many smaller peakers
- **Provinces are not receptive to the idea of a nuclear plant**: only Borssele (Zeeland) has emerged as a possible location, with Noord-Brabant 'willing to negotiate under certain conditions'

Potential solutions

- **More certainty around the political climate for nuclear power** could help to stabilise the uranium market and provide clarity to the TSO
- **Government diplomatic aid** in securing stable, long-term supply from numerous sources would add security of fuel supply and may help stabilise its price

Sources, Aurora Energy Research, Energeia

Nuclear power plants would require financial support; public concerns and lock-in effects would remain as hurdles

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Technological market readiness

- **The cost evolution potential of conventional nuclear power plants is limited**; these have, in fact, become more expensive over the past decades due to increasingly stringent safety requirements
  - Small modular reactor (SMR) technology may change this, but these are still experimental and not yet market-ready
- **Lead times for development and permitting are long** (10-15 years)
- **High dismantling costs** form a downside to investors
- **Few companies worldwide have the technical capabilities** for construction and maintenance of a nuclear plant

Potential solutions

- **Contracting multiple reactors simultaneously**, or partnering with other countries to this end, may help reduce costs and lead-in time
- **R&D support for SMRs** may help bring these to market

Political support & coordinative uncertainty

- **Nuclear waste, the risk of accidents, and the threat of the use of uranium in nuclear weapons** must all be managed sufficiently, and public concern for these issues is high
- **A long-term lock-in** would be the result of the long lifetime of nuclear plants
  - The baseload character of nuclear power may have an impact on RES uptake and could altogether alter the nature of the energy system – nuclear power would e.g. lower the potential of a hydrogen power generation breakthrough
- **SMR technology, being decentralised, would bring added risks and hurdles**, including many more points of nuclear waste generation (a logistic challenge) and security risk, necessary regulatory changes, and public opposition

Potential solutions

- **The state could guarantee insurance against the consequences of a nuclear disaster** for all citizens to put the population's minds at rest. Further, stringent regulations of waste and security will be necessary, and an information campaign could help the public put the risk into perspective. A proven technology such as Generation III+ would provide optimal safety
- **The possibility of a nuclear lock-in must be considered**, along with its system consequences
- **For SMRs, additional regulatory, logistic, and security adaptations will be necessary**

Expected lead-in time: 15-20 years

The building of a larger reactor can be expected to take at least 15 years.
For small modular reactors, time to reach commercial deployment needs to be added to the development time.

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Lithium-ion batteries' contribution can be enhanced through contracted congestion management and smarter taxation

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Market design and regulations

- **The Dutch imbalance market is not optimally attuned to smaller assets** participating as balancing service providers (BSPs): the asset owner carries the risk of not being called. These limits to participation mean that 'value stacking' options are limited due to the relatively small spread of the baseload price
- **Batteries with a grid connection are still subject to double taxation as of 2021**: power is taxed when the batteries charge and when provided to the end consumer; the government has announced to eliminate this taxation (see below)
- **The tax abolishment will not affect co-located batteries,** owing to the difficulty of writing a suitable tax plan for such assets
- **High grid connection tariffs** pose a discouragement to battery owners

Potential solutions

- **Grid operators could contract congestion management** over longer time periods (not unlike a PPA construction)
- **The Dutch imbalance market admits batteries** and is the only one in Europe to do so
- **Preferential regulations for batteries in the balancing market** (such as reduced tariffs) may increase their participation
- **Electricity storage will no longer be taxed as of 2022**[1]
- **Grid connection tariffs could be lowered or abolished** for batteries

Infrastructure, fuel, and space availability

- **The demand for lithium and other rare earth metals** is expected to rise significantly due to the global investment in batteries. Lithium already features on the list of raw materials the EU considers 'critical'
- **The Netherlands (and the EU) are dependent on imports** of these materials
- **Abundant renewable generation is needed** to ensure batteries' proper functioning

Potential solutions

- **Recycling capacity for these materials needs to be built up** and should be considered part of climate policy
- **More support for alternative battery technologies**, such as iron oxide, could reduce the risk of a run on lithium[2]

1) This change is part of the Tax Plan 2022, published on *Prinsjesdag* 2021. 2) A competitive prototype has been demonstrated by US start-up Form Energy.

Source: Aurora Energy Research

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Households currently have little to no incentive to flexibilise their demand, as they pay a fixed unit price for electricity[1]

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Market design and regulations

- **Households have no economic incentive to flexibilise their demand** (shift to low-load hours), as they generally see a uniform per-unit price for their electricity bill (alongside an equally unvarying fixed component)
  - Households generally prefer such low-risk (predictable, hedged) pricing, with the possibility of opting-in on flexibility when convenient
- **The interaction of third parties with household flexibility is not well-governed by guidelines[2] and may be hampered by regulations** limiting the purchase of flexibility services by DSOs[3]

Potential solutions

- **Flexible pricing contracts could provide households with an incentive** to flexibilise their demand, by passing on price signals from the wholesale market. Utilities could play a role here in stimulating households to switch to such contracts
- **The regulator is advised to set grid fees and/or taxes to vary** either directly (explicit link) or indirectly (via times of day) with grid congestion, renewable generation, etc.[3] (c.f. United Kingdom)
  - A regionally variable system would be efficient if it included the infrastructure to price power locally
- **Household grid fees and/or taxes could be set to depend on connection capacity**, incentivising households to flatten their demand profile (c.f. Spain)
- **The government is advised to set up guidelines on third-party access/control** of household demand (e.g. EV (dis)charging behaviour, data privacy standards)

Infrastructure, fuel, and space availability

- **It may be a technical challenge for the TSO and DSOs to coordinate** amongst a large number of small third parties which control and aggregate household demand (and, in the case of V2G[3], generation) flexibility[3]
  - Predicting electricity demand may become more challenging – at least in the short term during a learning period – if a large portion of consumers partially flexibilise demand based on power prices
  - This may be exacerbated by large amounts of consumer discharging to the grid through V2G
- **The development of grid infrastructure** (notably safe and secure data sharing from and control via smart meters) would present a further challenge[3]

Potential solutions

- **Third parties functioning as aggregating intermediaries** between consumers, the DSOs, and the TSO can help coordinate between and simplify the complexity for both consumers and the grid operators
  - E.g. utilities or EV service providers which contract and regulate a certain amount of flexibility from households aggregate this flexibility, and bid as a single entity on the electricity market
  - The government could engage the TSO, DSOs, and third-party intermediaries for discussions on aggregation and control of flexible demand and V2G
- **The TSO, DSOs** and the government could start to discuss the planning of sufficient smart meter infrastructure

1) N.B. The focus here is on stimulating flexible demand relative to non-flexible EV and heat-pump usage; not on stimulating uptake of EVs and heat pumps per se, which is a separate issue. 2) E.g., what insights and control they may be allowed over household energy consumption and timing. 3) 'V2G': Vehicle to Grid, i.e. bidirectional EV-charging. 3) See PwC's 2019 report on regulatory barriers for EV smart charging, notably slides 7-8

Source: Aurora Energy Research, PwC

Flexible heat pumps and smart EV charging are market-ready, although insufficient household insulation may prove a hurdle

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Technological market readiness

- **Flexible and bidirectional EV charging technologies are market-ready**, although the know-how for coordinating mass household flexibility and vehicle-to-grid may still be lacking
- **Flexible heat-pump operation is technically uncomplicated and market-ready**; however, such flexible heat-production may be made more complicated where it necessitates thermal storage or improvements in house insulation
  - Well-insulated houses can, themselves, act as a heat buffer, but at current no more than one in five homes in the Netherlands reach this standard
  - Thermal storage, coupled with a heat-pump, can also provide a heat-buffer and enable a large amount of flexibility; however, this adds another up-front cost to consumers

Potential solutions

- For coordination, see *Infrastructure, fuel, and space availability*
- **To improve the flexibilisation of household heat pump systems**, e.g. for the installation of thermal storage in combination with smart heat-pump control, the government could set incentives, provide subsidies, or even set requirements
- **Significantly increasing the number of houses insulated well enough to enable thermal buffering** would enable the deployment of more flexible heat-pumps, which could be achieved by setting incentives or subsidising high-level home insulation

Expected lead-in time: 1-5 years (EVs); 5-10 years (flexible heat pumps)

Flexible and bidirectional EV charging is technologically mature and, beyond cost, limited primarily by maladapted grid fees and the necessary learning time for implementation. The implementation of flexible heat-pumps is limited not only by abovementioned unvarying grid fees, but by the number of sufficiently well-insulated houses.

Sources: Aurora Energy Research, *Centraal Bureau voor de Statistiek*

High grid fees and insufficient infrastructure present obstacles to industrial DSR, alongside general hurdles for electrolysis

AURORA

Market design and regulations

- **High grid connection fees constitute significant costs** for large consumers of electricity (and thus for electrification), such as electrolysers or e-boilers
  - The current grid tariff structure further disincentivises demand flexibility via the *volumecorrectiefactor*: a grid tariff discount in the case of stable (high load-factor, >5700 hrs/y) demand
- **No hydrogen wholesale market yet exists in the Netherlands** (in the form of e.g. the TTF), adding uncertainty for parties interested in participating in such a future market
  - This is currently only a minor issue, however, as the nascent electrolysis industry can benefit from the security of a long-term bilateral contract with consumers
- **SDE++ subsidies are not linked directly times of high RES generation**, but only indirectly via a maximum number of hours per year

Potential solutions

- **The regulator is advised to restructure grid tariffs** to better incentivise large-scale flexibility, e.g. a reduction for flexible-demand installations that respond to price or certain signals from the TSO
- **The government could commence designing the Netherlands' future hydrogen market**[1], bringing investment security and enabling its direct implementation once infrastructure becomes sufficient
- **CO_2-abatement subsidies could be more directly linked to electricity consumption** only during moments of RES generation

Infrastructure, fuel, and space availability

- **Currently, renewable electricity generation is not sufficient** to make (flexible) electrification environmentally sensible
- **Little exists in the way of H_2 transportation and storage infrastructure**: pipelines, conversion/compression stations for shipping, salt caverns, etc.
  - Storage, especially, is a prerequisite for flex. electrolysis, and is only cheap on a large scale in salt caverns
- **The electricity grid is likely to experience congestion issues** if electric boilers and electrolysers are grid-connected
- **It may be a technical challenge for the TSO to coordinate** amongst a large number of small, flexible third parties

Potential solutions

- **The amount of RES generation should be increased** significantly to enable low-carbon electrification
- **The government and grid operator should accelerate hydrogen infrastructure** and storage buildout, including definition of long-term plans with hard financial backing
- **The government and grid operator may need to accelerate electricity grid reinforcement**, potentially combining this with incentives place large power offtakers at grid-optimal locations

1) Such a design should include the future availability of hydrogen and the future rules for its wholesale trading.

Source: Aurora Energy Research

Further development is needed to bring fully-flexible electrolysis to market, and much depends on future infrastructure developments

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Technological market readiness

- **Large-scale electrolysis is technologically mature**, but the traditional and best-developed technology, alkaline electrolysis, is somewhat less flexible than alternatives[1]
  - The scaling up of more flexible technologies (primarily PEM) is underway, but these are as of yet more expensive than alkaline electrolysis
  - Alkaline electrolysis is simultaneously being further developed to improve flexibility[1]
- **Flexible electric boilers are technically uncomplicated** and currently commercially available

Potential solutions

- **The government could provide a boost to the development and cost-reduction of more flexible electrolysis technologies** (which is superior in other aspects, too), such as PEM and solid oxide, by providing support for scale-up projects. Current support mechanisms focus on pilot projects (DEI+) and actual implementation (SDE++), but leave a gap for projects/technologies in between these two stages
  - The government could develop a subsidy scheme specifically focused on flexible technologies[2]

Political support & coordinative uncertainty

- **Many large (coordinative) uncertainties surrounding hydrogen exist** that are highly pertinent for the development of a hydrogen system in the Netherlands, including whether and when large-scale imports will be feasible, and a what price
- **The efficiency of electrolyser co-location versus a direct grid connection is unsure** and depends partly on the future development and capacity of the electricity grid. Hydrogen production may not always be the most efficient use of renewably generated electricity, and, inversely, stopping hydrogen production need not be the most societally efficient way to curb demand during moments of lower renewable generation.[3]

Potential solutions

- **The government is advised to create stable long-term hydrogen policy, plans, financial and infrastructural commitments** to lend investor certainty
- **The government could engage the TSO, electrolyser and renewable developers to find the socially optimal configuration for electrolyser connection** (colocation or grid connection, or both)

Expected lead-in time: 2-5 years[4]

Small- and mid-size PEM electrolysis projects already exist in multiple European countries.

1) See e.g. Brauns, Turek (2020) 2) Although the SDE++ does only subsidise a limited no. of hours per year, with the aim of only supporting production in hours of high RES generation, its direct focus is on CO_2 abatement and only indirectly on flexibility. Less flexible but cheaper technologies therefore have an implicit advantage over flexible but nascent ones, such as alkaline vs. PEM electrolysers. 3) However, for a grid-connected electrolyser to be possible and provide higher societal efficiency, sufficient power grid capacity to avoid congestion is a prerequisite. 4) A large-scale rollout would likely take 10-20 years. The main limiting hurdles are the lack of hydrogen infrastructure and RES deployment.

Source: Aurora Energy Research

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Economics of Technologies in Project Base Scenario 2030 – Hydrogen technologies

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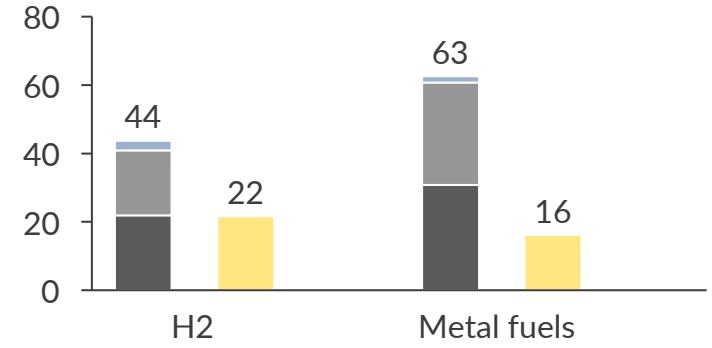
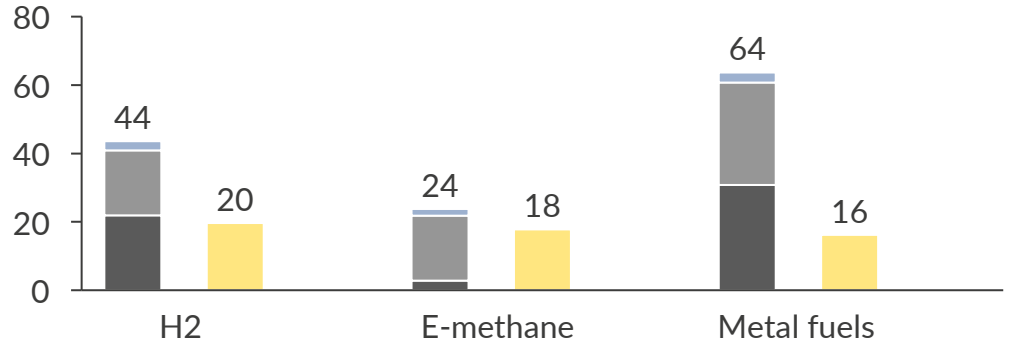
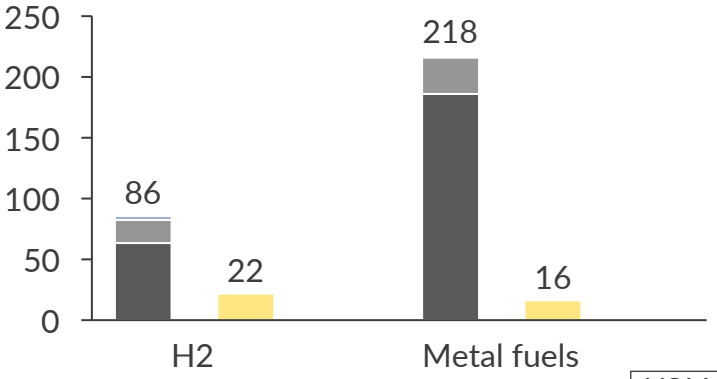
Business Case 2030 – Blue H2* technologies Retrofit
€/kW (real 2020)



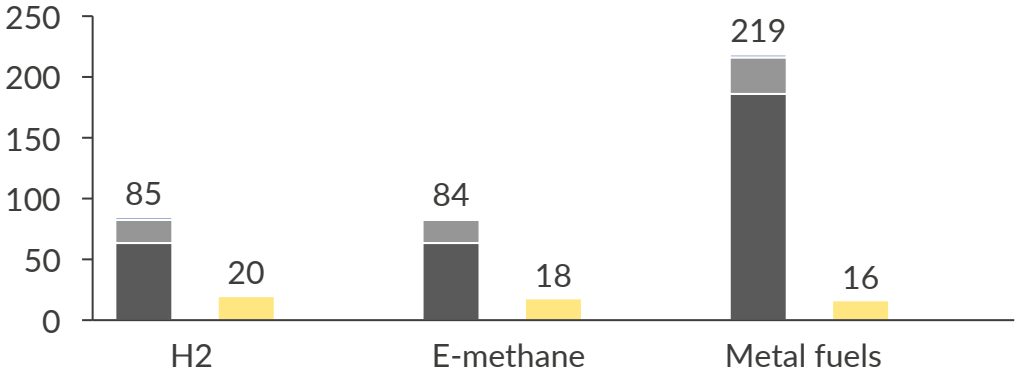
Business Case 2030 – Green H2 technologies Retrofit
€/kW (real 2020)



Business Case 2030 – Blue H2* technologies Newbuild
€/kW (real 2020)



Business Case 2030 – Green H2 technologies Newbuild
€/kW (real 2020)



VOM for some technologies are so low that they do not show

Capex | Fixed O&M | Variable Fuel | Variable O&M | Revenues

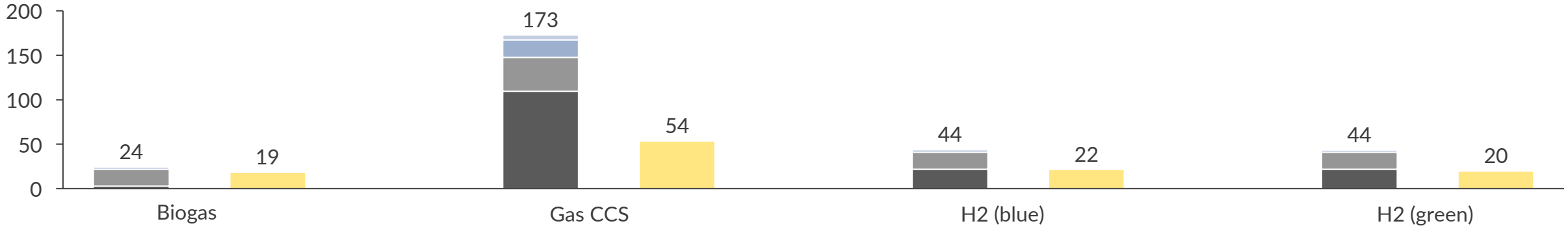
*) E-methane only included using green H2, as E-methane based on methane is no logical option; instead of blue E-methane one could better store the CO2 capture at the SMR and burn methane in the turbine

Source: Aurora Energy Research

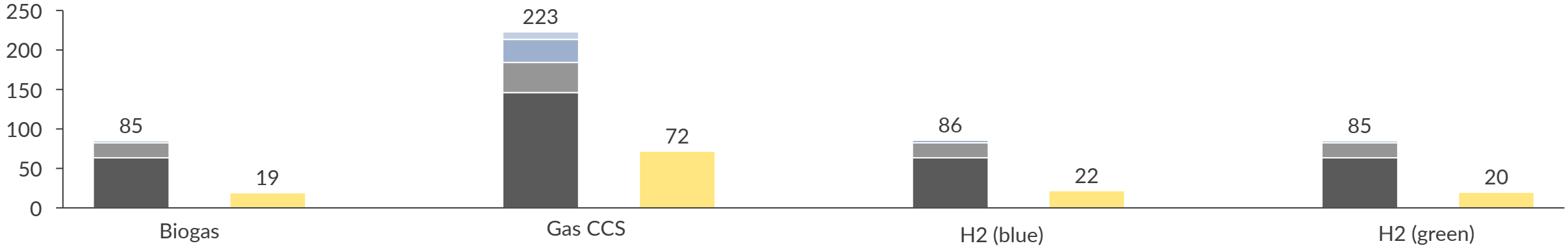
Economics of Technologies in Project Base Scenario 2030 – CCGTs

AURORA

Business Case 2030 – CCGT Retrofit
€/kW (real 2020)



Business Case 2030 – CCGT Newbuild
€/kW (real 2020)



Capex | Fixed O&M | Variable Fuel | Variable O&M | Revenues

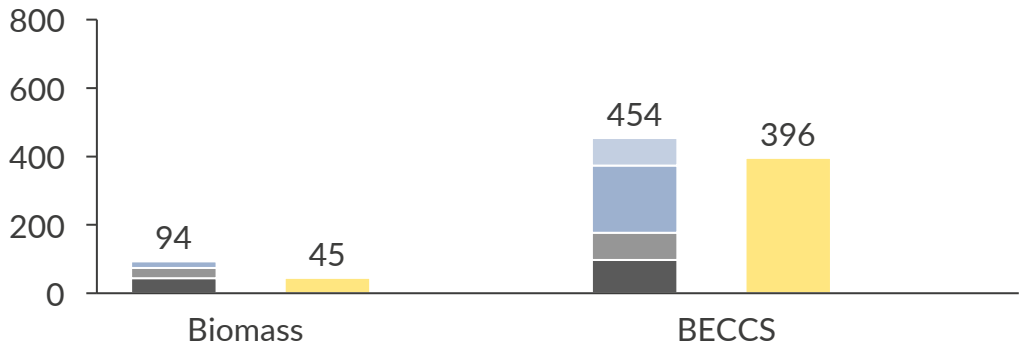
VOM for some technologies are so low that they do not show

Source: Aurora Energy Research

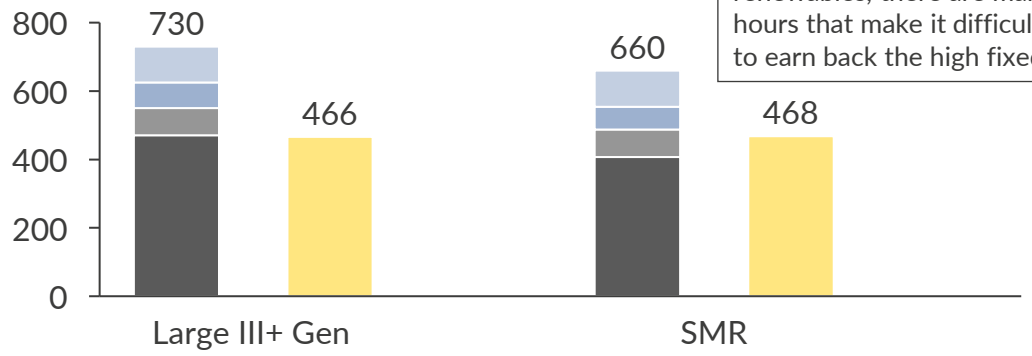
Economics of Technologies in Project Base Scenario 2030 – Biomass, Nuclear and Interconnections

AURORA

Business Case 2030 – Biomass Retrofit
€/kW (real 2020)

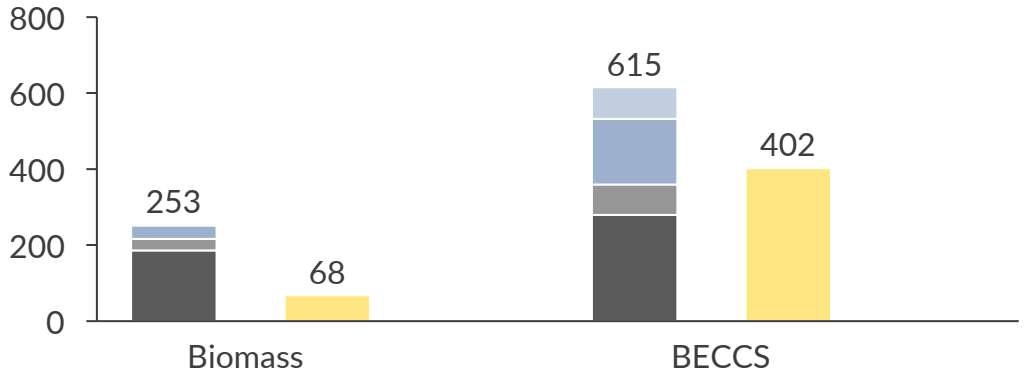


Business Case 2030 – Nuclear Newbuild
€/kW (real 2020)



In a system with high share of renewables, there are many low-price hours that make it difficult for nuclear to earn back the high fixed cost

Business Case 2030 – Biomass Newbuild
€/kW (real 2020)



Capex | Fixed O&M | Variable Fuel | Variable O&M | Revenues

VOM for some technologies are so low that they do not show

Source: Aurora Energy Research

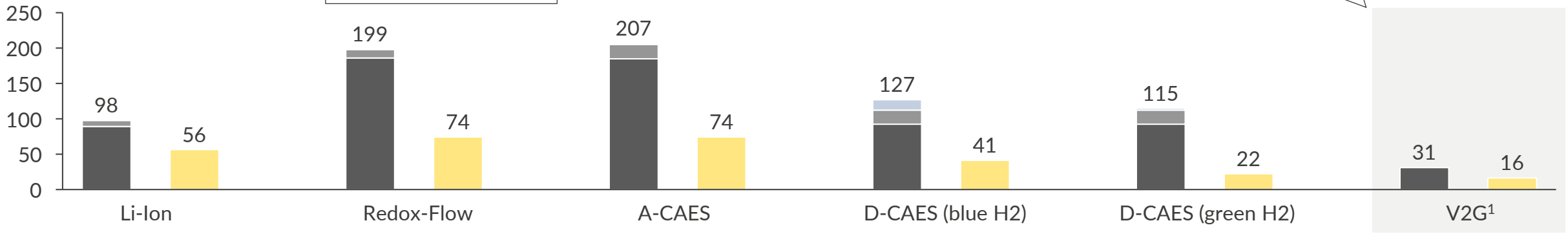
Economics of Technologies in Project Base Scenario 2030 – Batteries and Other Technologies

AURORA

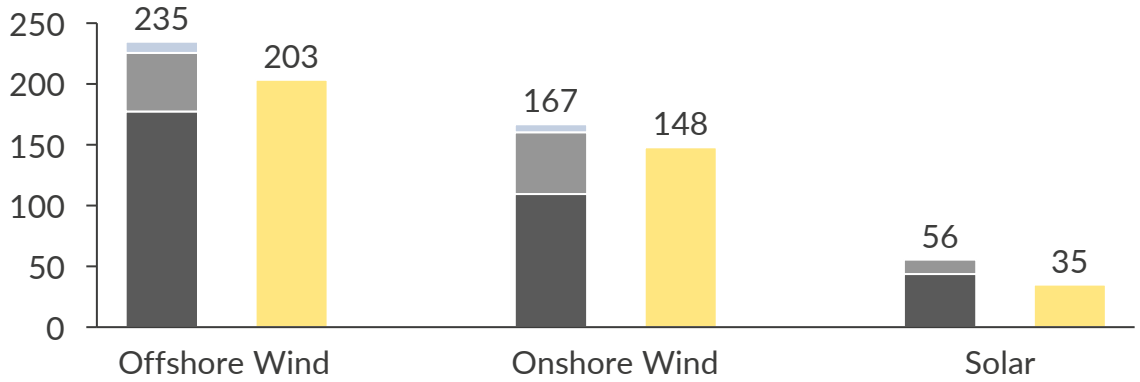
Business Case 2030 – Batteries
€/kW (real 2020)

For batteries, revenues are netted between power sales and purchases

Not chosen as best-in-class asset, given existing concerns on feasibility / scale by 2030

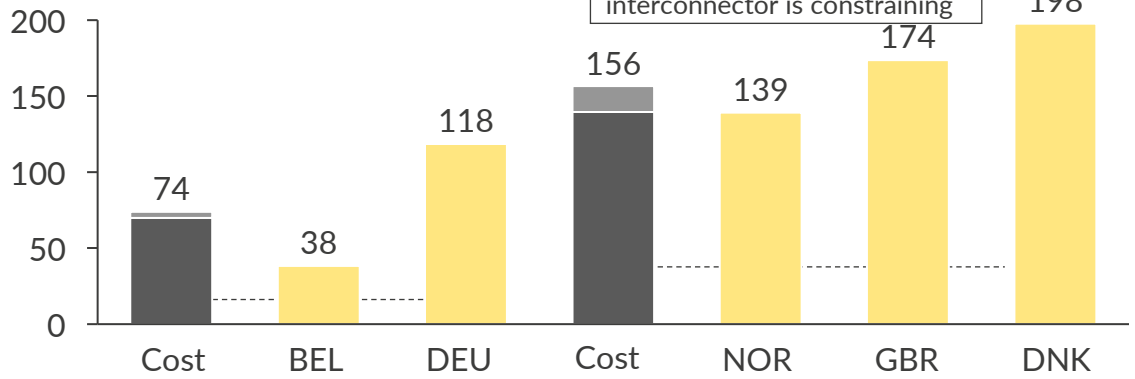


Business Case 2030 – Renewables
€/kW (real 2020)



Business Case 2030 – Interconnection
€/kW (real 2020)

Revenues calculated by taking rents (price differences) when interconnector is constraining



Connection via land – lower end of cost estimate

Connection sub sea – upper end of cost estimate

Capex | Fixed O&M | Variable Fuel | Variable O&M | Revenues

VOM for some technologies are so low that they do not show

1) Cost based on CAPEX for wall charger supporting bi-directional charging

Source: Aurora Energy Research

Agenda

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To quantify what would happen with a much higher capacity build out of long duration, an extra high nuclear scenario was created

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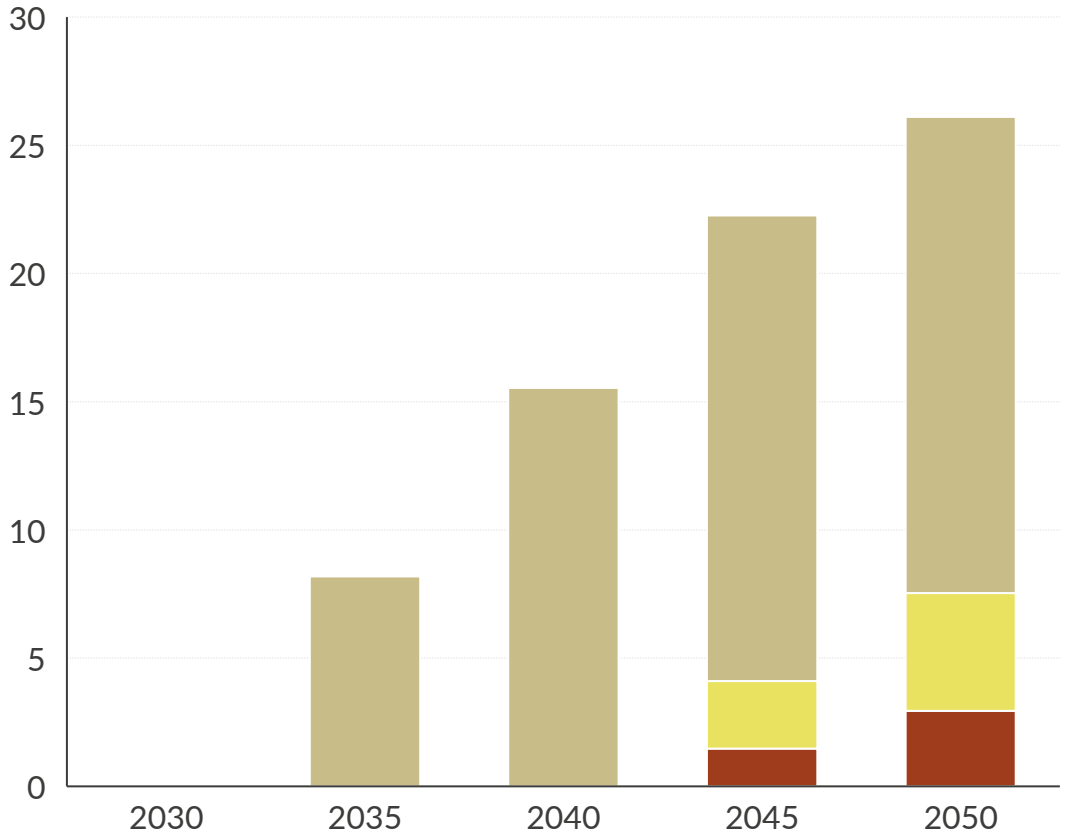
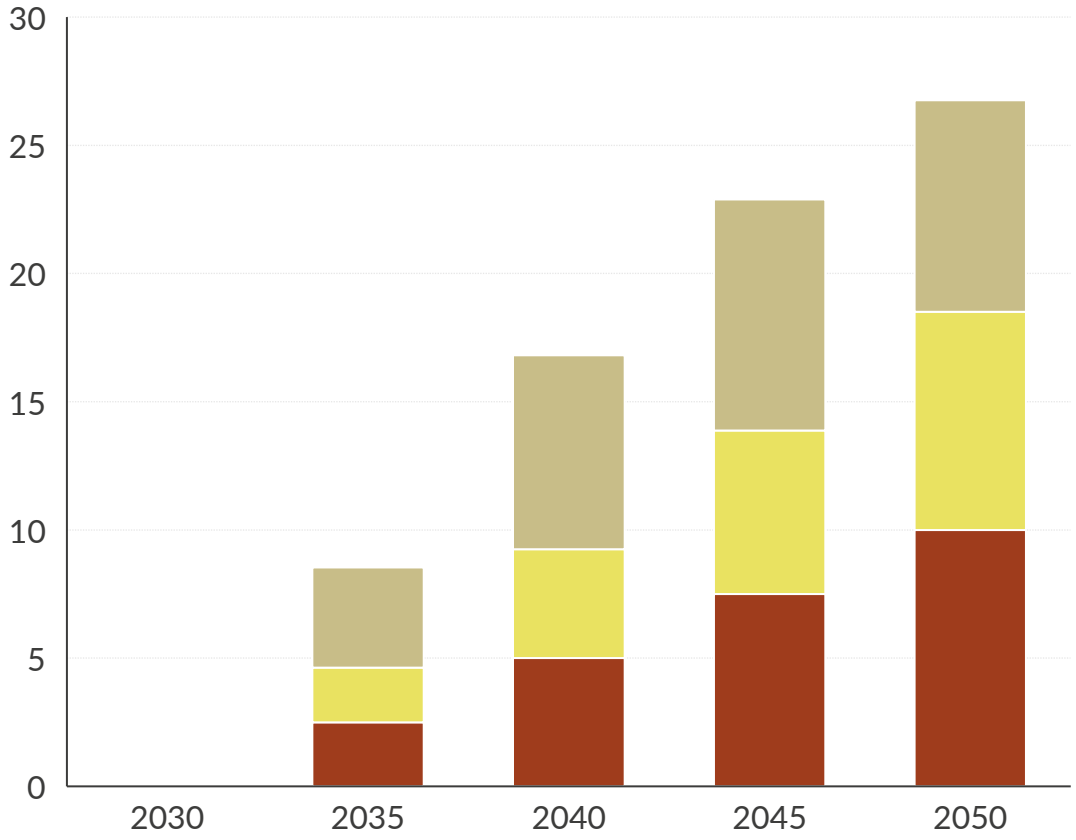
PRESENTED 17.09.21

CO_2 free flexible capacities – tech mix 2 – Full Security of Supply
GW



CO_2 free flexible capacities – tech mix 2 – high nuclear scenario
GW



Nuclear H2 CCGTs Li-ion Back-up

Source: Aurora Energy Research

A high nuclear scenario leads to strong cannibalisation of margins for flex technologies, low baseload prices and high system costs

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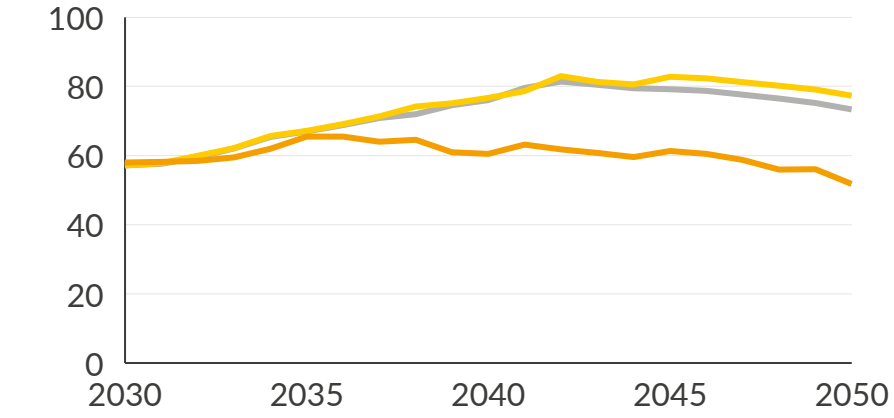
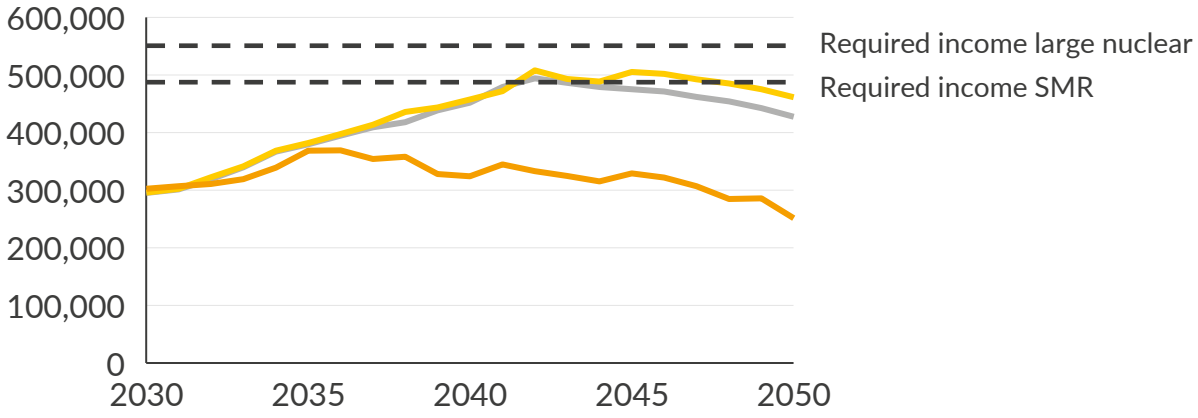
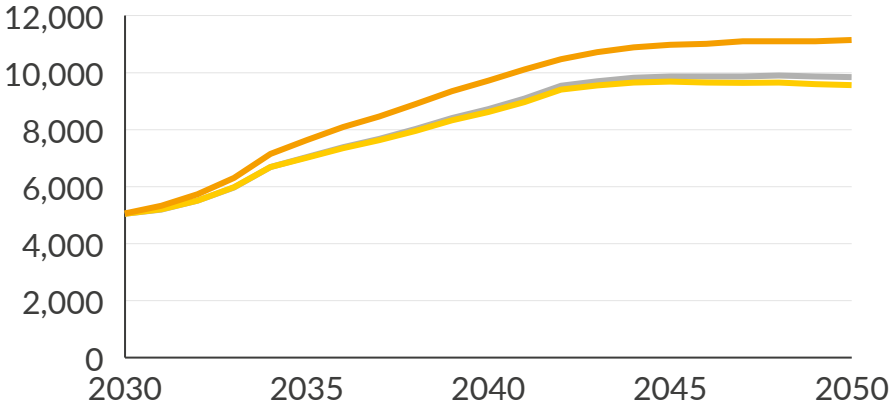
Baseload prices – tech mix 2
€/MWh (real 2020)



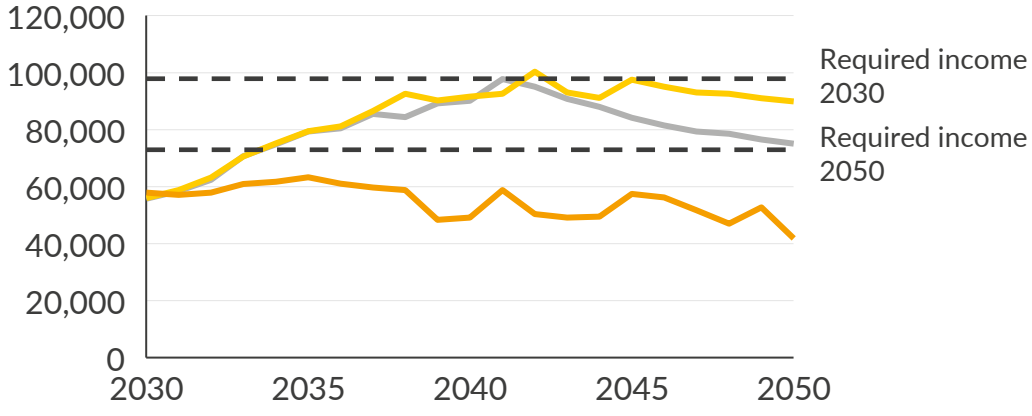
Nuclear margins[2] – tech mix 2
€/MW/year (real 2020)



System cost[1] total – tech mix 2
mio€ (real 2020)



Li-ion margins[2] – tech mix 2
€/MW/year (real 2020)



Full security of supply — Optimal profitability — High nuclear

1) System Costs means the sum of Capital Costs, Finance Costs, Operation and Maintenance Costs, and Commodity Costs. For this analysis all variable costs are taken into account, but only the fixed cost of the long-duration, short-duration and back-up capacity is taken into account. This will not affect the difference between scenarios, as all other fixed costs are the same in all scenarios. In the final report, the total fixed cost will be used to place numbers in perspective.
2) The margin reflects the net result from of revenue minus variable cost on the wholesale market. Source: Aurora Energy Research

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